RAILROAD COMMISSION OF TEXAS

OFFICE OF GENERAL COUNSEL

GAS UTILITIES SECTION

STATEMENT OF INTENT FILED BY	**§**	
ENERGAS COMPANY TO INCREASE	**§**	
RATES CHARGED IN THE ENVIRONS	**§**	**GAS UTILITIES DOCKET**
OF 67 WEST TEXAS CITIES;	**§**	**NOS. 9002-9135**
PETITION BY ENERGAS COMPANY	**§**	
FOR REVIEW OF 67 MUNICIPAL	**§**	
RATE DECISIONS	**§**	

PROPOSAL FOR DECISION

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PROPOSAL FOR DECISION

I. INTRODUCTION

This case involves the consolidated dockets of Energas Company's (Energas' or the Company's) appeals of the municipal rate decisions of 67 West Texas Cities (Cities), and Energas' Statement of Intent to increase rates in the environs of those 67 Cities. Energas provides natural gas service in the Cities and in several other cities that comprise its "West Texas System," all of which are inter-connected by an unaffiliated city gate pipeline system. Energas is the Texas operating division and business unit of Atmos Energy Corporation.[1]

Energas proposes a general rate increase, on a West Texas System-wide basis, that would increase current annual revenues of approximately $45,700,000 by about $10.3 million, a proposed increase of 22.5% over normalized revenue at present rates. Energas also proposed two new rate riders, or surcharges. First is the Steel pipe Improvement Program (SPIP) Rider, which would produce approximately $211,079 in revenue per year. Second is the System Expansion Rider (SER), which would produce approximately $55,569 in revenue per year. Energas also proposes to change its Gas Cost Adjustment (GCA) clause by a revenue-neutral conversion of all of the cost of gas and related revenue taxes and franchise fees from base rates to the GCA. Finally, Energas proposes to increase its charges for miscellaneous services such as reconnecting gas service following termination.

For the portion of this rate increase that is applicable to customers in the environs of the 67 Cities, Energas proposes the same rates, rate riders, GCA, and charges for miscellaneous services as those inside the Cities. The expected annual revenue increase from the 22,275 environs customers is $1,010,617. Also, Energas estimates that the SPIP Rider would produce $25,460 of revenue per year from the environs, and the SER Rider would produce approximately $6,380 in revenue per year from the environs.

Forty-six of the sixty-seven Cities intervened as parties to the appeals dockets. No environs customers intervened in the proceeding; however, all dockets were consolidated for

[1] Energas' Post-Hearing Brief at p. 1

hearing purposes, and this Proposal for Decision (PFD) contains recommendations for all appeals and environs dockets.

The parties initially attempted to settle the issues in this case through mediation. Energas entered into mediation with the Cities' "steering committee" in May 2000, arriving at a settlement that was ratified by 59 out of the 67 Cities. The eight Non-Settling Cities proceeded through an evidentiary hearing with Energas, and argued that Energas' revenue requirement should be reduced, rather than increased. The Examiners' recommendation contained in this PFD indicates that Energas' revenue requirement has increased $4,374,147, a 9.57% increase over normalized revenue at present rates.

II. PROCEDURAL HISTORY AND NOTICE

A. PROCEDURAL HISTORY

Energas Company (Energas) is a gas utility serving the sixty-seven (67) West Texas Cities of Abernathy, Amherst, Anton, Big Spring, Bovina, Brownfield, Village of Buffalo Springs, Canyon, Coahoma, Crosbyton, Dimmitt, Earth, Edmonson, Floydada, Forsan, Friona, Hale Center, Happy, Hart, Hereford, Idalou, Kress, Lamesa, Levelland, Littlefield, Lockney, Lorenzo, Los Ybanez, Lubbock, Meadow, Midland, Muleshoe, Nazareth, New Deal, New Home, O'Donnell, Odessa, Olton, Opdyke West, Palisades, Pampa, Panhandle, Petersburg, Plainview, Post, Quitaque, Ralls, Ransom Canyon, Ropesville, Seagraves, Seminole, Shallowater, Silverton, Slaton, Smyer, Springlake, Stanton, Sudan, Tahoka, Tanglewood, Timbercreek, Tulia, Turkey, Vega, Wellman, Wilson, and Wolfforth, Texas, and their environs.

Energas filed Statements of Intent with all of the 67 Cities on August 4, 1999, and all 67 Cities denied the rate increase. The first of the Cities took final action on or about February 7, 2000. The last of the Cities made its final rate decision on March 7, 2000. Energas filed with the Commission its *Petitions for Review of Municipal Rate Decisions* of the 67 Cities' municipal rate decisions on March 8, 2000 and March 30, 2000, under Texas Utilities Code Section 103.005 *et seq*. The appeals were docketed as Gas Utilities Docket (GUD) Nos. 9069-9135 (appeals dockets).

On March 8, 2000, Energas also filed with the Commission its *Statement of Intent to Change Environs Gas Rates and Motion to Consolidate* as to the environs of the same 67 Cities, under Texas Utilities Code Section 104.102. The Statement of Intent was docketed as GUD Nos. 9002-9068 (environs dockets).

The Commission received letters objecting to the proposed rate change from the following individuals: Royce and Marcella Durham, Robert Lee and Toni Meinecke, and Julia Carillo. On April 27, 2000, the Docket Services Section of the Office of General Counsel received eighteen pages of signatures indicating protests to Energas' proposed rate increase. The protests were forwarded to the Commission by Maria Contreras. The Examiners provided the above individuals an opportunity to file petitions to intervene, but none did.

The Examiners granted the following Motions to Intervene from a total of 46 out of the 67 cities named in the appeal, all represented by Jim Boyle, Attorney. On April 5, 2000 the Cities of Plainview, Earth, Odessa, New Home, Nazareth, Big Spring, O'Donnell, Ransom Canyon, Coahoma, Seminole, Panhandle, Tulia, Olton, Smyer, Sudan, Opdyke West, Springlake, Friona, Midland, Silverton, Timbercreek, Pampa, Lockney, Kress, Seagraves, Village of Lake Tanglewood, Idalou, Littlefield, Vega, Ralls, New Deal, Amherst, and Wilson filed a Motion to Intervene. On April 26, 2000, the Cities of Bovina, Brownfield, Crosbyton, Hale Center, Happy, Hart, Lamesa, Muleshoe, Post and Quitaque filed a Motion to Intervene. On May 3, 2000, the Cities of Edmonson and Lorenzo filed a Motion to Intervene.

Fifty-nine (59) of the Cities (Settling Cities) ratified a Settlement Agreement reached with Energas; eight of the Cities did not ratify the Settlement Agreement. The cities that did not ratify the Settlement Agreement were Big Spring, Brownfield, Hale Center, Lamesa, Levelland, Lubbock, Shallowater, and Wolfforth, Texas (Non-Settling Cities).

On August 15, 2000, Mr. Boyle filed a Motion to Withdraw as attorney for all of the Settling Cities and Substitute Counsel for the Cities of Odessa and Midland. The Examiners granted the Motion on August 17, 2000, and added Mr. Geoffrey Gay, Attorney, representing the Cities of Odessa and Midland, to the service list. Although Mr. Gay's representation of the Cities of Midland and Odessa inure to the benefit of the other Settling Cities, the Examiners recognized that the other Settling Cities that intervened in this matter are not technically represented by counsel, so the Examiners added those Cities to the service list, including those city representatives as supplied by Mr. Boyle. The Examiners recognize the rights of all 67 Cities to standing in this proceeding, under Texas Utilities Code § 103.023(a), and have "consolidated" them under Texas Utilities Code § 103.023(b).[2]

The Examiners approved three abatements of this matter, with Energas' written agreement to extend the statutory deadlines, under Texas Utilities Code §§ 103.055(c) & 104.107, to December 5, 2000 for both the appeals and environs dockets. These abatements occurred from May 23-June 2, 2000; June 8-August 4, 2000; and October 11-24, 2000. The parties agreed to the abatement periods as necessary to accommodate settlement discussions to December 5, 2000. The Examiner set a procedural schedule that contemplates Commission action by December 5, 2000.

The hearing on the merits convened on August 28, 2000 and continued through September 6, 2000. Initial briefs were filed on September 18, 2000. Reply briefs were filed on September 25, 2000. A hearing on rate case expenses was held on October 10, 2000, and briefs on rate case expenses were filed on October 17, 2000. Energas and the Cities provided a compilation of rate case expense food and beverages on October 23, 2000, as requested by the Examiners. The Examiners also allowed into the record an additional RFI Response that was referred to in Mr. Pous' testimony, and a worksheet, provided by Energas, detailing the calculations supporting an expense for Customer Service Center-related O&M expense.

The Commission approved temporary rates for the 59 Settling Cities, and bonded rates for the environs of all 67 Cities, on October 25, 2000.

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[2] TEX. UTIL. CODE ANN. § 103.023(a)&(b) (Vernon 1998).

B. NOTICE

Energas properly provided notice for both its appeal and its Statement of Intent.

1. NOTICE OF STATEMENT OF INTENT

Prior to its proposed effective date of April 27, 2000, Energas published notice of its *Statement of Intent to Change Environs Gas Rates and Motion to Consolidate* as to 67 Cities' environs for four successive weeks in newspapers which collectively have general circulation in each county containing territory affected by the proposed increases, under Texas Utilities Code §104.103(a)(1).[3] Energas accomplished this by publishing notice in *all* of the newspapers within the West Texas Service Area in question.[4]

2. NOTICE OF ENERGAS' APPEALS

Energas filed its *Petition for Review of Municipal Rate Decisions* as to sixty-one cities on March 8, 2000. Service of the Petition for Review to these sixty-one cities was made by first-class U.S. mail, postage prepaid, also on March 8, 2000, as required by Texas Utilities Code § 103.054(a).[5] The Petition was timely filed, under Texas Utilities Code § 103.054(b), because it was filed not later than the 30th day after the dates of the final decisions of the governing bodies, the earliest being February 7, 2000.[6]

Energas filed a subsequent *Petition for Review of Municipal Rate Decisions and Motion to Consolidate* as to six additional cities on March 30, 2000.[7] Service of the Petition for Review as to five of these six cities was timely made, under Texas Utilities Code § 103.054(a), through their attorney of record, Jim Boyle.[8] Service for one of these six cities was made through the representation provided by the West Texas Steering Committee.[9] This Petition was timely filed, under Texas Utilities Code § 103.054(b), because it was filed not later than the 30th day after the dates of the final decisions of the governing bodies, the earliest being March 7, 2000.[10]

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[3] TEX. UTIL. CODE ANN. § 104.103(a)(1) (Vernon 1998); Prehearing Ex. 4 at pp. 2-3; Prehearing Exs. 5&6; Prehearing Ex. 8 at pp. 1-2; *See also* Prehearing Ex. 3. The form of notice was approved in Examiner's Letter No. 5.
[4] Prehearing Ex. 8, at p. 2.
[5] TEX. UTIL. CODE ANN. § 104.054(a) (Vernon 1998); Prehearing Ex. 4 at pp. 1-2.
[6] Energas' Post-Hearing Brief, Appendix I: Commission Jurisdiction.
[7] Prehearing Ex. 7.
[8] Petitions to Intervene filed April 5, 2000; Tr. Vol. 9 at pp. 7-8, p. 186, lns. 21-24; Prehearing Ex. 9.
[9] Prehearing Ex. 10.
[10] Energas' Post-Hearing Brief, Appendix I: Commission Jurisdiction.

II. JURISDICTION

The Commission has jurisdiction over the matters at issue in this proceeding under Texas Utilities Code §§ 102.001(a), 103.051, 104.001, and 121.151.[11] The statutes and rules involved include, but are not limited to, TEX. UTIL. CODE ANN., Chapters 101, 102, 103, 104, 105, and 16 TEX. ADMIN. CODE, Chapters 1 & 7. The Notice of Hearing was issued in these Dockets on July 31, 2000 to all parties and satisfied the requirements of 16 TEX. ADMIN. CODE § 1.45 (West 1999) and of TEX. GOV'T CODE ANN. § 2001.052 (Vernon 2000).

IV. RATE BASE

Energas requests rate recognition of a total net "original cost" rate base of $119,568,615 for its West Texas System.[12] The Cities have proposed a series of adjustments to various rate base items that would reduce Energas' requested net original cost rate base by $21,887,674, for a total rate base of $97,680,941.[13] As shown on Examiners' PFD Schedule E, the Examiners recommend a reduction to Energas' requested rate base of $3,953,760, for a total net "original cost" rate base of $115,614,855. The adjustments recommended by the Examiners are as follows:

- Removal of $3,189,002 in severance costs and outplacement fees
- Removal of $ 128,033 in Micon Consulting fees
- Removal of $ 782 in IT-related costs
- A negative adjustment of $635,942 to Energas' proposed Cash Working Capital

A. ALLOCATION OF NEW TECHNOLOGY INVESTMENTS

Energas is the Texas operating division and business unit of Atmos Energy Corporation.[14] Atmos recently invested in new information technology (IT). The amount allocated to Energas is $33,930,993, including the SCT/Banner Customer Information System (CIS), Customer Support Center (CSC), and Oracle back-office systems, plus the associated start-up costs of each. The Cities propose that Energas' requested amount be reduced by $18,170,351, or 53.5%, to $15,760,642. The West Texas System's allocated portion of these IT costs is approximately $24.0 million, and the Cities propose adjusting this amount downward by $13,019,983.[15]

Energas' allocated portion of Atmos' IT costs is 24.72%, while Energas' West Texas System's allocated portion is 71.0377% of Energas' allocated costs, making the West Texas System's allocated portion approximately 17.6% of Atmos' IT costs, according to Energas' witness, Mr. Cagle.[16] Atmos currently has 1,025,000 customers nationwide. The Cities first

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[11] TEX. UTIL. CODE ANN. §§ 102.001, 103.051, 104.001, 121.051 (Vernon 1998).
[12] Energas' Post-Hearing Brief at p. 6; Energas' Ex. 5, Sch. 7, ln. 22.
[13] Cities' Ex. 97B, Sched. SEC-2 at p. 6, ln. 15.
[14] Energas' Post-Hearing Brief at p. 1.
[15] Cities' Ex. 91 at pp. 24-26 & Sched. DJL-7; Energas' Ex. 1 at p. 17.
[16] Energas' Ex. 5 at p. 16.

proposed to reduce the allocation of IT costs to the West Texas system by allocating the costs among a hypothetical 2,000,000 customers. In the alternative, the Cities propose that the IT investment be allocated among either: (1) 1,352,000 customers, which includes the acquisitions of 48,000 Missouri Natural Gas customers in Missouri and 279,000 customers in the Louisiana Gas Service (LGS) system in Louisiana; or (2) 1,073,000 customers, which includes only the Missouri acquisition. The Missouri acquisition occurred in June 2000, and the Louisiana acquisition has not yet occurred.

Contested Issue: Should the information technology (IT) portion of Energas' rate base be reduced by including the Missouri and Louisiana customers in the allocation calculation?

Examiners' Recommendation: No. The Examiners recommend that Energas' rate base include the IT investment as allocated using Atmos' existing 1,025,000 customers, excluding the 48,000 customers in the Missouri system acquired in June 2000, and the 279,000 customers in the LGS (Louisiana) system.

1. ENERGAS' POSITION

Energas argues that the IT investment should be allocated among its 1,025,000 existing customers, without either the Missouri or the Louisiana acquisitions. Energas makes three arguments against the Cities' proposed adjustment.[17]

First, Energas argues that the Cities are incorrect that the IT investment is oversized. Energas points out that the Cities' witness, Mr. Lawton, agrees that he did not undertake an independent examination of the features and capabilities of the technologies at issue; Mr. Lawton also does not contend that the old legacy systems did not need replacement, or that the IT investments were imprudently incurred. Also, Mr. Lawton characterized his adjustment as an "excess capacity" adjustment, though he did not employ the "used and useful" test to reach his conclusion.[18] Finally, Energas points out that Mr. Lawton relied on the statements of Mr. Best, the Company CEO and President, who indicated that the system could handle two million customers with little incremental investment.[19] Energas argues that these statements were made in a non-technical context and do not constitute good evidence of the technical capabilities of the system.

Second, Energas argues that as the various impacts of the Missouri and Louisiana acquisitions are not yet known and measurable, they should not be included in allocating the costs of Atmos' technology investments. The Missouri acquisition of 48,000 customers closed in June 2000, more than a year after the test year in this proceeding. Further, the Louisiana acquisition of 279,000 customers will not close until sometime in 2001, if it closes at all. Mr. Lawton conceded that these acquisitions will affect other ratemaking factors besides the number of customers, and that it would take "a good bit of time" for the effects of the acquisitions to "fall

[17] Energas' Post-Hearing Brief at pp. 6-18.
[18] Tr. Vol. 6 at p. 186, lns. 12-13.
[19] Tr. Vol. 6 at p. 194, lns. 4-22.

out" and be discernible.[20] Thus, "it would create a serious mismatch and constitute piecemeal ratemaking if the Commission were to simply add in the Missouri and Louisiana customers in the asymmetrical manner recommended by Mr. Lawton and the non-settling Cities."[21]

Third, Energas argues that the Cities' proposal to use two million customers is not based upon any known facts and circumstances as they exist today, but upon hypothetical future events that provide no sound analytical basis for a rate base disallowance. Thus, Energas proposes that Mr. Lawton's conclusion that Atmos' IT systems are "oversized" is based on hypothetical, not actual, facts. [22]

Finally, Energas argues that uncertain merger effects should not be included in this rate determination, consistent with the Commission's decision in the Lone Star/Enserch case, GUD No. 8664.[23] In that case, the Commission declined to include a Finding of Fact proposed by the Examiners that would include the effects of Lone Star's impending merger with Texas Utilities Corporation, and instead ordered Lone Star to file a statement of intent three years after the effective date of the merger, for consideration of the changes in the cost of service from the merger savings.[24] Energas requests that it be allowed the same consideration to report back in three years with a quantification of the various impacts on Energas' cost structure due to these acquisitions.[25]

2. CITIES' POSITION

The Cities argue that the IT investments should be allocated using 2,000,000 customers, to recognize the capacity of the additional systems Atmos has purchased. Mr. Fischer, Energas' President, acknowledged that, hypothetically, if rates are set for Energas without taking into account the customers from these additional systems, those rates would be too high.[26]

The Cities claim that adding new customers to the system affects the allocation of costs. They introduced Cities' Exhibit 44, which shows that the percentage allocation to Energas dropped from 34.92% to 24.72% when Atmos' 1997 merger with United Cities Gas Company was included. Further, Mr. Best, Atmos' President and CEO, recognized that, as the Company grows, it will be able "to spread not only our technology costs, but all of our costs, over a larger base of customers."[27] The Cities also argue that the evidence in the record shows that the CIS initiative was built to accommodate Atmos' continued customer growth, which is Atmos' goal.

In their initial brief, the Cities included a recalculation of the allocation of these investments to reflect two options: (1) the addition of 48,000 Missouri customers in June 2000

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[20] Energas' Ex. 36 at p. 43, ln. 23 – p. 46, ln. 4; Tr. Vol. 6 at p. 195, lns. 11-17.
[21] Energas' Post-Hearing Brief at p. 11.
[22] Energas' Post-Hearing Brief at p. 15.
Tex. R.R. Comm'n., *Statement of Intent of Lone Star Gas Company and Lone Star Pipeline Company, Divisions of Enserch Corp. and Ensat Pipeline Company To Increase the IntraCompany City Gate Rate,* Gas Utilities Docket No. 8664.
[24] *Id*, Second Order on Rehearing Nunc Pro Tunc (Nov. 25, 1997), Revised and Restated FOF No. 16.
[25] Energas' Reply Brief at p. 12.
[26] Tr. Vol. 1 at p. 53.
[27] Cities' Ex. 4 at p. 5.

(2) the addition of both the 48,000 Missouri customers and the 279,000 Louisiana customers that will result from the acquisition of the Louisiana Gas Service system. The "Missouri only allocation" produces a downward adjustment of $3,744,887 - from $33,930,993 to $28,704,725. The "Missouri/Louisiana allocation" produces a downward adjustment of $7,844,000 from $33,930,933 to $22,984,109.

Finally, the Cities argue that the Commission has already addressed this issue in GUD No. 8033, where Southern Union Gas Company included in its rate filing the acquisition of two gas utility systems in South Texas and reflected the reduction of allocated expenses from those acquisitions, but not from two acquisitions that occurred after the filing of its case. The Commission concluded that the allocation should include the new post-filing acquisitions even though there would be some offsetting costs in the future that were not currently known and measurable based on the Examiners' recommendation that "the possibility of some offsetting costs in the future does not render the allocation of existing corporate costs immeasurable."[28]

3. EXAMINERS' ANALYSIS

The Examiners recommend that the CIS system investment included in Energas' rate base be allocated using the existing 1,025,000 Atmos customers, without the 48,000 Missouri customers acquired in June 2000, and without the 279,000 customers in the LGS (Louisiana) system not yet acquired. The effects of these acquisitions, and their attendant impacts, are not fully known and measurable.

The Examiners' recommendation is consistent with case law and Texas Public Utility Commission (PUC) rules that require the attendant impacts of a post-test year adjustment to be known and measurable. Texas courts have determined that changes occurring after the end of a test year for which attendant impacts are not known and measurable are to be considered in the next rate proceeding: "The inquiry into reasonable operating expense is a 'snapshot' inquiry based on the test year. It is not intended to account for future cost changes. Adjustment for these changes will be made in future rate cases."[29] Also, PUC Substantive Rule 23.21(b) states "Post test year adjustments for known and measurable changes to historical test year data (including, but not limited to revenue, expenses, and invested capital) will be considered only where the attendant impacts on all aspects of a utility's operations can be with reasonable certainty identified, quantified, and matched."[30] The Examiners' recommendation is consistent with this guidance.

Although the number of ratepayers in the Missouri system is known, the attendant impacts are not. The acquisition became final in June 2000, after testimony was filed in this case. Energas does not yet know the related costs of the Missouri acquisition, so it would be unfair to increase the number of customers in this allocation without increasing the associated

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[28] Tex. R.R. Comm'n, *Appeal of Southern Union Gas Company from the Action of the Cities of Groves, Nederland, Port Arthur, and Port Neches, Texas*, Gas Utilities Docket No. 8033, Proposal For Decision at pp. 23-24 (Feb. 10, 1992), Order at p. 76.
[29] *Cities of Abilene v. PUC*, 854 S.W.2d 932, 943 (Tex. App.--Austin 1993), aff'd in part and rev'd in part on other grounds, 909 S.W.2d 493 (Tex. 1995).
[30] 16 TEX. ADMIN. CODE § 23.21(b) (West 1999), *repealed at* 24 Tex. Reg. 1367 (February 26, 1999).

costs accordingly. To do so would cause a matching problem. Thus, the Missouri acquisition should not be taken into account until the attendant impacts can be determined.

Likewise, the Commission should exclude the Louisiana acquisition from the allocation of these costs because the change is not known or measurable at this time. Instead, the evidence indicates only that the acquisition is likely to take place. The acquisition was far from complete in the test year when the majority of the CIS purchase costs were incurred. The evidence indicates that there are regulatory hurdles to overcome before the acquisition takes place, but that it might occur as early as the first quarter of 2001.[31] Thus, the Examiners agree with Energas that the Louisiana customers should not be included in the allocation until the acquisition actually occurs, and the change, with its attendant impacts, is known and measurable.

Finally, the Examiners reject the Cities' claim that the CIS system was purchased to accommodate two million customers, so the customers in Energas' West Texas System are being allocated too large a percentage of the investment cost. The evidence shows that the CIS system was purchased with acquisitions in mind, and that it has the *capability* of being expanded to accommodate two million customers. Nonetheless, the evidence also shows that the CIS system was purchased to handle all of the current customers, and that some costs would be incurred in expanding it for future acquisitions. This is true for the CIS, the field hardware, the Customer Support Center, severance, training, other start-up costs, and the license fee for the Oracle system, which is expandable on a "per seat" basis.[32] The Oracle system is an example of an additional cost that would be necessary to expand the system to accommodate two million customers, because the Company must purchase additional software licenses for each "seat" using the Oracle software. Even the Banner CIS software license, which had to be purchased on a flat fee basis, was purchased to serve existing customers.[33] Mr. Pearson's testimony supports this argument: "[w]ith client/server systems, there is no need whatsoever to build-in a lot of excess capacity because by [their] very nature, client/server systems are modular in design and can grow as a Company's needs grow."[34] Thus, the evidence points to the conclusion that the CIS system was purchased for Atmos' existing customers and should not be allocated among two million hypothetical customers.

The Examiners are likewise convinced that Atmos' IT investment is used and useful to Atmos' current customers. In fact, the Cities did not attempt to argue that the CIS purchase was not all used and useful to the customers. Mr. Lawton, the Cities' witness, admitted that he did not pursue the argument that this investment was not all used and useful.[35] Instead, he attempted to use the allocation of costs to exclude some of the CIS system's cost from the rate base allocated to the West Texas System ratepayers. The Cities also did not demonstrate that the purchase price of the CIS system would have been less if Atmos purchased a system that was

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[31] Tr. Vol. 1 at p. 82; Energas' Post-Hearing Brief at p. 14.
[32] Tr. Vol. 9 at pp. 145, 148, 149, 152, 154-156, & 164. Mr. Guy testified on Tr. Vol. 9 at p. 164 that "per seat" means per user, "the people who are going to use the system. You pay so much license for each one of those. . . . I think you have to purchase seats licenses 50 at a time or something like that." Mr. Guy did not identify exactly what the increase would be.
[33] *Id.* at pp. 145 –147.
[34] Energas' Ex. 13 at p. 7, lns. 21-25.
[35] Tr. Vol. 6 at p. 186, lns. 12-13.

only large enough for the current customers without the ability to be expanded. Consequently, the Examiners agree with Energas that the IT investment is all used and useful to the current customers.

Finally, the Examiners recommend that the Commission order Energas to report back in three years to determine the effects of the mergers and acquisitions, as suggested by Energas. Because the Commission does not have continuing original jurisdiction over the rates the utility charges within the municipal limits of these 67 Cities, the Commission can only do so for the environs' customers. If the rates become unreasonable because of the future effects of Atmos' acquisitions, the Cities may exercise their original jurisdiction to remedy them.

B. 10% RETAINAGE AND AUDIT

Contested Issue: Should 10% of the-related costs be excluded from rate base pending a Commission-ordered outside audit of the IT project costs, as recommended by the Cities?

Examiners' Recommendation: No. The Cities did not provide adequate evidence to warrant either a 10% disallowance or a Commission-ordered audit.

1. ENERGAS' POSITION

First, Energas argues that the Cities' proposed "retainage" is actually a disallowance that is premised on such a flimsy and methodologically flawed analysis that its adoption would be arbitrary and confiscatory.[36] The IT project costs were incurred and booked over a period of almost five years and consist of over 20,000 separately-booked transactions. Because they were booked and maintained in accordance with NARUC accounting standards, they carry a presumption of validity for ratemaking purposes under Commission Rule 7.58, unless specifically controverted by probative evidence showing they were unreasonably incurred.[37] The Company argues that Ms. Coleman's haphazard review and analysis of those accounting records is insufficient to overcome that presumption.

Second, Energas argues that Ms. Coleman's analysis has no rational relation to her calculated adjustment.[38] Ms. Coleman employed a haphazard and biased sampling "method," and never produced any results on which to reasonably premise her recommended adjustment. Rather, Ms. Coleman had the Company provide 1,400 invoices out of more than 20,000 items on the list of IT-related invoices. She reviewed these invoices and identified some that she found problematic, but Ms. Coleman never determined how many of the 1,400 entries were improper, or even the dollar amount of the invoices that she deemed potentially at issue. Thus, her 10% retainage amount has no rational basis.

[36] Energas' Post-Hearing Brief at p. 21.
[37] 16 TEX. ADMIN. CODE §§ 7.58 (West 2000).
[38] Energas' Post-Hearing Brief at p. 23.

2. CITIES' POSITION

The Cities claim that Energas failed to meet its burden of proving that the costs underlying its investment in new technology are just and reasonable, because the documentation that Ms. Coleman reviewed was "rife with examples of exorbitant or inappropriate costs that do not belong in rate base."[39] Ms. Coleman cites a number of examples in her testimony. Ms. Coleman also testifies that hundreds of pages of this documentation were either blank or illegible, and that others lacked back-up invoices.[40] Thus, the Cities propose an adjustment of $2,505,295 to Energas' plant in service, and that an audit be performed by an outside audit firm so the Commission can determine how much of this "retainage" should be added back to rate base.

3. EXAMINERS' ANALYSIS

The Examiners recommend denial of the 10% retainage and outside audit recommended by Ms. Coleman. Energas testified that it has kept these accounts in accordance with NARUC standards, as required by Commission Rule 7.58, so it enjoys the presumption of correctness, and has met its burden of proof as to those expenses left unchallenged by Ms. Coleman. Even though Ms. Coleman's review of the invoices indicates that some inappropriate costs may be included, Energas is correct that her analysis is non-mathematical, so her testimony does not warrant the withholding of 10% of the investment, or an outside audit.

First, the Examiners believe that Energas has met its burden of proof for those expenses not brought into question by Ms. Coleman, under the presumption of reasonableness in Commission Rule 7.58. It is true that Ms. Coleman has brought into question some of these costs. Nonetheless, Energas demonstrated on cross examination that Ms. Coleman's analysis of these invoices was statistically unsound and incomplete. It appears that Ms. Coleman picked the worst examples she could find upon a cursory review, and then suggests that an outside audit attempt to determine whether there are any more. Therefore, because Ms. Coleman's non-mathematical analysis does not bring into question all of the expenses, the Examiners do not believe that Ms. Coleman's sampling overcomes the presumption of reasonableness for the rest of the expenses, or even for a definitive percentage of them. Other than those invoices in Ms. Coleman's testimony, the costs are assumed to be reasonable as kept in accordance with NARUC standards.

The Examiners rely on Mr. Guy's testimony that Ms. Coleman's haphazard review and analysis of those accounting records is insufficient to overcome a presumption of correctness, and that her sampling technique fell far short of acceptable methodological standards.[41] On cross-examination, Ms. Coleman admitted that she could have obtained a valid sample based on intervals from the list, a valid statistical sampling technique.[42] Instead, in her own words, she selected "a small non-mathematical sample" of cost items from the list the Company had provided, requested back-up support, and noted "several items" that, in her opinion, "should not

[39] Cities' Initial Brief at p. 17.
[40] Tr. Vol. 7 at pp. 116, 123; Cities Ex. 97 at p. 33.
[41] Energas' Ex. 24 at pp. 8-9.
[42] Tr. Vol. 7 at p. 131, lns. 10-21.

be included in rate base."[43] Ms. Coleman states: "I did not employ a statistical technique. I non-mathematically just randomly selected costs throughout the Company's 500 pages of report just to get a sample of what the Company had included."[44]

Ms. Coleman's selected invoices for Atmos amount to $4,453,[45] which, when allocated to Energas' West Texas System, results in a disallowance of $782.[46] The Examiners have included a negative adjustment of this amount in their schedules because Energas did not provide adequate support for these expenses once questioned.

The Examiners do not recommend disallowance of the $250,000 performance bonus paid by Atmos to Ernst & Young (E&Y) for early completion of services rendered in connection with the IT project that Ms. Coleman questioned. According to Mr. Guy, this amount was properly paid by Atmos pursuant to an incentive clause built into its contract with E&Y, and it reflects normal practice for projects of this type and scale, whether in industry or government.[47]

Second, the record does not indicate that a 10% disallowance is warranted. Ms. Coleman admitted that her sample was non-mathematical, and she did not indicate that ten percent of her sampled invoices were unreasonable, or provide any other basis for her recommendation.[48] The Examiners also disagree with the Cities' argument that it is not a disallowance, but rather a postponement, pending the outcome of Ms. Coleman's recommended audit of this account. The removal of 10% would effectively disallow this amount from being included in the rates that the Commission will set in this case.

Finally, the Examiners agree with Energas that the Commission should not order an outside audit because there is no evidence in the record that indicates that this option is available or workable. On cross examination, Ms. Coleman admitted that she didn't know what an audit would cost, though she opined that "[t]he Company would, along with the Commission, find somebody who would be reasonable and would be able to perform this audit as quickly as possible for this Commission."[49] It is not clear who would pay for such an audit. No evidence in the record indicates that Ms. Coleman's suggestion to have the Commission perform an audit would generate a definitive answer in a timely manner. Any future attempt to determine the proper amount of Energas' rate base will necessarily involve data that is current at that time. Instead, the Examiners recommend that the Commission determine the proper rate base amount based on the amounts Energas has proved in the record in this case. Therefore, the Commission should not order an outside audit.

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[43] Cites' Ex. 97 at p. 32, lns. 16-18.
[44] Tr. Vol. 7 at p. 122, lns. 18-22.
[45] Cities' Ex. 57, Summarized in Cities Reply Brief at p. 18.
[46] Using the allocation factors in Mr. Cagle's testimony, Energas' Ex. 5 at p. 16, as recommended by the Examiners in the first issue in the Rate Base section of this PFD. ($4,453 x 24.72% x 71.0377%)
[47] Energas' Ex. 24 at p. 9, lns. 4-9.
[48] Cities' Ex. 97 at p. 32.
[49] Tr. Vol. 7 at p. 131.

C. SEVERANCE COSTS AND OUTPLACEMENT FEES

Energas claims $3,189,002 in rate base for severance costs and outplacement fees. Sara Coleman testified that this amount is the West Texas System's allocated share of Atmos' cost of $10,075,680 for these severance costs and outplacement fees, using the allocation supplied by the Company, and the Company does not contest the amount allocated.[50]

<u>Contested Issue</u>: Should the severance costs and outplacement fees associated with the installment of the IT in the amount of $3,189,002 be included in rate base?

<u>Examiners' Recommendation</u>: No. The Commission should remove the severance costs and outplacement fees from rate base.

1. ENERGAS' POSITION

Energas first argues that $3,189,002 in severance costs and outplacement fees should be included in rate base because they were necessarily and reasonably incurred in conjunction with, and as a direct result of, the establishment of the Customer Support Center and the efficiencies created by the Company's various technology upgrades.[51] These costs arose from reductions in workforce (RIFs) made possible by the Company's technology upgrades. Mr. Guy testified that these severance and outplacement costs here at issue should not be distinguished from other IT-related costs that are not "brick-and-mortar" investments. These costs were necessarily incurred by Atmos and Energas in conjunction with the CSC, CIS, and other technology improvements.[52] Thus, they "integrally relate" to the very changes and upgrades in information technology that are now producing the savings in O&M costs.

Second, Energas argues that the severance and outplacement costs were properly included in rate base and capitalized in order to effectuate a matching of the costs and benefits of the IT investments and to ensure that those costs are equitably recovered from both present and future ratepayers.[53] Mr. Guy testified as follows:

> Consistency and sound ratemaking theory *require* that the capital investments that have made these savings possible be recognized in rate base so as to enable the Company to earn a fair return on them. To do otherwise, as Ms. Coleman recommends, would result in a mismatch that ignores the fundamental trade-off that normally exists between efficiency or productivity investments, on the one hand, and the operational savings they make possible, on the other.[54]

Mr. Guy also testifies that capitalizing these costs in rate base "furthers 'intergenerational equity' between the interests of present and future ratepayers to recover costs of this nature over the

[50] Cities' Ex. 97 at p. 32, lns. 4-7.
[51] Energas' Post-Hearing Brief at p. 18.
[52] Energas' Ex. 24 at pp. 6-7.
[53] Energas' Initial Brief at p. 20.
[54] Energas' Ex. 24 at p. 6, ln. 31 – p. 7, ln. 8.

entire period of time that the productivity investments will be generating benefits to ratepayers."[55] Energas argues that these costs were prudently incurred and integrally related to the technology upgrades and business process changes that are producing, and will continue to produce, significant cost savings over the service lives of those new systems, and should be included in rate base.[56]

Finally, Mr. Guy testified that virtually *all* costs included in capital projects, if viewed in isolation, might be deemed "non-recurring." Thus, Ms. Coleman's argument that these costs are non-recurring should be rejected because it would mean that no investment would ever be includible in rate base if her argument were carried to its logical extreme.[57]

2. CITIES' POSITION

The Cities argue that the $3,189,002 in severance costs and outplacement fees should be removed from rate base because (1) they are non-recurring, (2) they are not properly classified as plant costs, and (3) while Energas has benefited from these salary reductions over the past two years, they have not proposed any offsets to cost of service to recognize these savings. The Cities argue that this violates the matching principle; if ratepayers are required to pay these costs, they should also receive the benefits associated with them.

Most importantly, the Cities argue that the Company has failed to quantify the savings it has realized from this investment in new technology, and has not reflected those savings in their rate filing. Mr. Guy describes these as "significant O&M savings," but has not identified exactly what they are.[58] The Cities also point to Atmos' representations that the new IT systems "have helped cut operation expenses by 24%, helping boost the Company's earnings."[59] Thus, the Cities argue that the Company has failed to quantify any savings in this case: "if the Company wants to recover the cost of its new technology investments, it should identify the 24% reduction in expenses it claims those investments have produced and reflect them in their rate filing as well."[60] To keep all of these savings from going to the shareholders, the Cities recommend removing the $3,189,002 from Energas' proposed rate base.[61]

3. EXAMINERS' ANALYSIS

The Examiners recommend denial of the West Texas System's $3,189,002 allocated portion of Atmos' Severance Costs and Outplacement Fees as a rate base item. This expense is non-recurring, and should not be included in rate base or earn a return. Also, Energas has not identified or proved the savings that have resulted from its IT investments, so the expense should not be allowed without the offsetting savings. Also, Energas has benefited from these salary reductions over the past two years, but has not proposed any offsets to cost of service to

[55] *Id.*at p. 7, lns 12-16.
[56] Energas' Post-Hearing Brief at p. 20.
[57] Energas' Ex. 24 at p. 6, lns. 16-23.
[58] Energas' Ex. 24 at p. 7.
[59] Cities 'Ex. 94 at p. 1 (Pipeline & Gas Journal). *See also* Cities' Ex. 8 at p. 2.
[60] Cities' Reply Brief at p. 21.
[61] Cities' Initial Brief at p. 19.

recognize these savings.

First, Energas should not be allowed to earn a return on these severance costs and outplacement fees, and they should not be included in rate base. Energas claims that they "integrally relate" to the IT investments which have caused savings in O&M costs, so they should be included in rate base.[62] However, Energas has failed to demonstrate exactly how these severance costs and outplacement fees actually relate to the implementation of its technology improvements. While the Examiners understand that certain non "brick-and-mortar" costs, such as computer technician time that is required to install the IT purchases, could be included in rate base, the Examiners fail to see how the cost of a reduction in force (RIF) resulting from new technology improvements is properly classified as a rate base item. Energas may be commended for reducing its unnecessary personnel, but the costs of doing so should not be put in rate base to earn a return.

Second, Energas has not identified or proved the savings that have resulted from its IT investments, so this should not be allowed as a rate base item without the offsetting savings that Energas claims it receives.[63] Even if Energas is correct that these costs are integrally related to the IT investment, Energas has not identified the source of the 24% reduction in expenses, and has not offset this one-time cost with those savings. Therefore, Energas has not met its burden to prove how these one-time costs are to be included in its rate base.

Energas does not address an alternative means of recognizing this expense, either. Energas does not explain whether these severance costs and outplacement fees relate to payroll expense. Energas did not address whether these severance costs and outplacement fees could be properly classified as payroll expense or offset by reductions in payroll. Energas did not address whether there were corresponding salaries that were *not* paid because of these outplacements. The payroll expense should have already been reduced to reflect these RIFs, but the record does not demonstrate whether Energas matched this expense with payroll savings during the test year, and Energas does not clearly identify the payroll reduction and other savings that are related to these costs.

D. MICON CONSULTING FEES

Energas has included $128,033 in rate base for fees associated with its consulting contract with Micon Consulting, Inc. (Micon). With the assistance of Micon, Atmos initially selected Price Waterhouse (PW) to provide the Customer Information System (CIS), part of the total IT investment. However, during contract negotiations with PW, Atmos learned that there was apparent collusion in the bidding process between the president of Micon and a senior partner at PW.[64] Atmos hired the firm of James Martin & Company to advise it on its CIS selection, and began a new selection process, resulting in the selection of SCT to be the CIS provider.[65] Atmos hired the law firm of Fried, Frank, Harris, Shriver & Jacobson (Fried Frank)

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[62] Energas' Post-Hearing Brief at p. 19; Energas' Ex. 24 at pp. 6-7.
[63] Cities' Ex. 94 at p. 1 (Pipeline & Gas Journal). *See also* Cities' Ex. 8 at p. 2.
[64] Tr. Vol. 5 at p. 39.
[65] Energas' Ex. 14 at p. 9.

to investigate.[66] With the help of this firm, Atmos sought $11 million in damages from PW, but eventually settled for $1.5 million.[67] Atmos did not seek recovery from Micon for the fees it paid under the consulting contract.[68]

Contested Issue: Should $128,033 in fees paid to Micon Consulting be disallowed?

Examiners' Recommendation: Yes. Energas did not meet its burden to prove that the fees paid to Micon Consulting were a reasonable and necessary cost that should be included in rate base.

1. ENERGAS' POSITION

Energas argues that this cost is properly included in rate base. The amount was paid to Micon for information and services provided in (1) identifying and evaluating Atmos' options for the upgrade of its CIS, (2) developing a set of specifications, and (3) evaluating bids for the project.[69]

Energas first responds to the Cities' argument that there had been a duplication of efforts between Micon and James Martin & Company (JMC), whom Atmos retained to review and confirm the wisdom of its selection of SCT as the winning vendor to replace Price Waterhouse (PW). Mr. Guy fully explained how Micon brought the unmatched combination of proprietary technical information and evaluative techniques to the process, which benefited Atmos, even after Micon's services were terminated.[70] Further, Energas claims that Micon's services were not duplicated.

In addition, Energas argues that, if the Cities imply that Atmos was wrong in selecting Micon, they are incorrect. Fried Frank found no culpability on behalf of Atmos in its selection of Micon. Fried Frank also found nothing irregular about Atmos' bidding practices, only the questionable behavior of PW and Micon, which Atmos knew nothing about. Further, Atmos acted correctly when it found out about the collusion by immediately suspending the bidding process and retaining outside counsel to investigate the matter. Atmos then purchased an off-the-shelf system from SCT that cost far less than that proposed by PW. Finally, Atmos reached a reasonable settlement with PW, producing a $1.5 million credit. Nothing in the record indicates that Atmos can be faulted for its selection of Micon.[71]

2. CITIES' POSITION

The Cities recommend that rate base be reduced by $128,000 for fees associated with the Company's consulting contract with Micon because there was a duplication of efforts. Micon was the consulting firm Atmos hired to advise it in the selection of a vendor for its CIS. Based

[66] Energas' Ex. 17, Schedule B.
[67] Tr. Vol. 5 at p. 54.
[68] Tr. Vol. 5 at pp. 40-41, 49-52, 57-58.
[69] Energas' Post-Hearing Brief at p. 25; Cities' Ex. 97 at p. 29.
[70] Energas' Post-Hearing Brief at p. 26.
[71] *Id.* at p. 27.

on the Fried Frank investigation and recommendations, Atmos decided not to seek damages against Micon. Instead, it sought to recover damages of $11 million from Price Waterhouse, eventually settling for $1.5 million.[72]

The Cities argue that ratepayers should not be required to pay the cost of the consulting fees Atmos paid to Micon because Micon was at fault for causing Atmos to repeat the CIS evaluation and selection process, resulting in a duplication of those costs.[73] Also, Atmos declined to pursue any course of action against Micon, which had breached its fiduciary duty to Atmos. Thus, ratepayers should not be required to pay for a cost for which Atmos made no attempt to seek recourse.[74]

3. EXAMINERS' ANALYSIS

The Examiners recommend excluding the $128,033 in fees paid to Micon Consulting from rate base because Energas has not proved that this amount is a reasonable and necessary rate base item. Micon was at fault for causing Atmos to repeat the CIS evaluation and selection process, and Energas did not prove that the services performed by Micon were not duplicated.

The Examiners' main concern is that ratepayers should not be required to pay a Company that apparently and breached its fiduciary duty and defrauded Atmos. Atmos' failure to seek monetary damages from Micon does not change the fact that Atmos was forced to repeat the CIS evaluation and selection process because of Micon's kickback scheme. Mr. Morley, the Fried Frank partner who specializes in internal corporate investigations, testified that Atmos acted prudently in this matter, and "reasonably decided that it would be overly expensive and time-consuming, and apparently fruitless, to pursue its claims against Micon."[75] Nonetheless, a "reasonable" action by Atmos does not equal a reasonable and necessary expense that should be included in rate base and borne by the ratepayers.

Also, Energas did not adequately prove that there was no duplication of efforts. The Examiners are unconvinced by Mr. Guy's testimony because Mr. Guy does not detail the benefit received from Micon that was not duplicated by SCT: "[n]either SCT nor JMC subsequently duplicated this contribution by Micon to the CSI evaluation and selection process, and it is quite doubtful that they ever could have. Therefore, despite Micon's questionable conduct in favoring PW over other competing CIS vendors, it is my opinion and belief that Atmos did receive value for the fees it paid to Micon."[76] Also, "receiving value" for an expense does not make it a reasonable and necessary rate base item for which ratepayers should be required to pay a return. Instead, as Ms. Coleman states, "Energas selected SCT Consulting to review and help select Energas' new CIS system. This was a duplication of efforts and ratepayers should not be required to pay for these types of infidelities of consulting companies that were selected by Energas."

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[72] Cities' Initial Brief at pp. 20-21; Tr. Vol. 5 at pp. 54-56.
[73] Cities' Initial Brief at p. 21; Cities' Ex. 97 at p. 30.
[74] Cities' Initial Brief at p. 21; Tr. Vol. 5 at pp. 40-41, 49-52, 57-58.
[75] Energas' Ex. 17 at p. 4, lns. 17-20; *See also* Energas' Ex. 17 at pp. 3-4; Tr. Vol. 5 at pp. 56-57.
[76] Energas' Ex. 24 at p. 4, lns. 21-25.

E. CASH WORKING CAPITAL

Cash Working Capital (CWC) refers to the amount of cash the Company needs to have on hand to meet its day-to-day cash operating requirements that are not already reflected in rate base. A lead-lag study empirically identifies the difference in timing between outward cash flow for labor, materials and supplies, inventory, and other expenses, and inward cash flow of revenue from payments by customers.[77]

CWC is a rate base item, and depending on whether the lead/lag study results in a positive or negative number, CWC will either increase or decrease the amount of rate base.[78] A lead/lag study compares the Company's revenue lag with its expense lead. The revenue lag is the amount of time between when the Company provides service and when the money it receives for the service is available for use. As the number of days of revenue lag increase, the cash working capital requirement increases. The expense lead is the amount of time between when the Company receives a product or service and when it pays for it. As the number of days of expense lead increase, the CWC requirement decreases.

If the Company pays its vendors and suppliers more quickly than it receives cash from ratepayers, then the CWC requirement is positive and will be added to the rate base. Conversely, if it takes longer for the Company to pay its vendors and suppliers than it does for customers to pay the Company for its service, the CWC requirement is negative and will be subtracted from the rate base.[79]

Therefore, cash working capital requirements may be positive or negative.[80] Positive working capital is investor-supplied.[81] In contrast, negative working capital reduces the need for investor-supplied capital and arises when the utility receives customer payments before service is rendered, or when it receives funds before it must satisfy a corresponding liability.[82]

To illustrate the concept of cash working capital, if one assumed that the utility paid for natural gas before it received payment for the natural gas it supplied to the consumer, then the utility would be using positive cash working capital, i.e., money from its investors, to pay for the natural gas until the consumer paid the utility. In that case, the investor would have an expectation of receiving a reasonable return on its investment. If, however, the consumer paid the utility in advance for use of the product, the Company has negative cash working capital and the investor would have no expectation of return because the investor's capital was not being used.[83] Ultimately, a determination of working capital is an exercise of discretion as to what particular method yields the most fair and equitable result in each case.[84]

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[77] *Colorado Municipal League v. Public Util. Comm'n*, 687 PR 2d, 416, 420; *Cent. La. Elec. Co. Inc. v. La. Pub. Serv. Comm'n*, 373 So.2d 123, 130 (La. 1979).
[78] Tr. Vol. 2 at pp. 12-13.
[79] Cities' Initial Brief at pp. 21-23.
[80] *Cincinnati Gas & Elec. Co. v. Pub. Util. Comm'n*, 620 N.E.2d 821 (Ohio 1993).
[81] *Colorado Municipal League v. Public Util. Comm'n*, 687 PR 2d, 416, 419.
[82] *Id.*
[83] *Zia Natural Gas Company v. New Mexico Public Utility Commission*, et al., 2000 WL 358390 (March 1, 2000).
[84] *General Tel. Co. v. Arkansas Pub. Serv. Comm'n*, 23 Ark.App. 73, 744 S.W.2d 392, 397 (Ark.Ct.App.), aff'd, 295 Ark. 595, 751 S.W.2d 1 (1988).

In this case, both the Company and the Cities have prepared lead/lag analyses to determine the appropriate amount of CWC for Energas. In its rebuttal, Energas proposes a CWC requirement of $7,719.[85] In their Reply Brief, the Cities recommend a CWC requirement of negative $1,076,521.[86] This represents a change from the original CWC proposed by the Cities, as well as the revised CWC presented by the Cities during the hearing.[87] Some of the changes are merely flow-through changes resulting from some of the Cities' proposed adjustments in other areas of the case. Other CWC changes made at the hearing by the Cities are more significant.

Energas' lead-lag study evaluated the funds and lead/lag days in seven categories: 1) Purchased Gas; 2) O&M, Payroll Regular; 3) O&M, Payroll-PTO; 4) O&M, ESOP; 5) Other O&M; 6) Federal Income Tax; and 7) Other Taxes.[88] The parties are in dispute on all of these categories. The Cities' witness, Mr. Pous, raised several issues regarding the Applicant's lead/lag study. First, the Cities argue that the dollar value associated with purchased gas should be adjusted to reflect known and measurable changes to gas costs since the test year. Second, the Cities argue that the revenue lag should be adjusted downward by one-half day since not all customers pay by check, as the Company assumes.[89] Third, the parties dispute the appropriate number of lead days to calculate CWC "Payroll-Paid Time Off" (PTO). Fourth, the parties dispute the appropriate number of lead days to calculate CWC "Other O&M". Fifth, the parties dispute the appropriate number of lead days to calculate CWC "Federal Income Tax (FIT)." Sixth, the parties dispute the appropriate number of lead days to calculate CWC Taxes Other Than Federal Income Tax.[90]

As shown on Examiners' Schedule E-2, the Examiners recommend a Total Cash Working Capital amount of negative $628,223. This amount is based on the Examiners' recommendations, discussed below, and results in a negative adjustment of $635,943 to Energas' proposed $7,719 CWC.

1. VALUE OF PURCHASED GAS

<u>Contested Issue</u>: Should the Dollar Value of Purchased Gas be $47,963,957 as proposed by Energas, or $108,261,995, as proposed by the Cities?

<u>Examiners' Recommendation</u>: The Examiners recommend a CWC Purchased Gas Cost of $74,537,396.

CWC attributable to purchased gas is based on the average daily amount of revenue that is passed through to cover gas costs multiplied by the difference between the payment lead and revenue lag days.[91] The Cities argue that the CWC requirement for purchased gas should include

[85] Energas' Ex. 4A, Revised Rebuttal Schedule THP-5.
[86] Cities' Reply Brief, Second Revised Exhibit JP-17.
[87] Cities' Ex. 98A, Second Revised Exhibit JP-17.
[88] Energas' Ex. 4A, Revised Rebuttal Schedule THP-5.
[89] Cities' Initial Brief at p. 30.
[90] Cities' Reply Brief at pp. 26 & 30; Energas' Post-Hearing Brief at pp. 33-36.
[91] Energas' Post-Hearing Brief at p. 29.

an updated value for purchased gas to reflect known and measurable changes to gas cost since the test year.[92] The Company argues that the Commission should rely on test year gas cost because the recent cost of gas is not known and measurable in relation to what the Company should expect over an entire year, nor is it known and measurable in relation to any variations in demand that are affected by price fluctuations.[93]

1.a. Energas' Position

Energas proposes to use the test year average gas cost of $47,963,957 to calculate its Purchased Gas CWC requirement.[94] The Company argues that the test year data provides the average of a full year's worth of gas cost fluctuations as reflected in its books and records, whereas the Cities base their proposed gas cost on a single month's price.[95] Also, the Company notes that Mr. Pous does not take into consideration the basic economic premise that demand and consumption may wane when the price of the commodity increases. Mr. Pous leaves the volume for the test year unadjusted.[96]

1.b. Cities' Position

The Cities propose to increase test year gas cost by $60,297,995, which results in a CWC Purchased Gas Cost of $108,261,995.[97] The Cities argue that the adjusted dollar value associated with purchased gas reflects known and measurable changes to gas cost.[98] For his adjustment, Mr. Pous used Energas' billed gas costs for the month of June 2000 for West Texas.[99] Cities argue that using June 2000 gas cost, rather than more current, higher predictions, more than makes up for any reductions in consumption as a result of higher gas prices.[100]

1.c. Examiners' Analysis

The Examiners recommend a $26,573,439 increase to the Company's proposed CWC Purchased Gas Cost, which results in a CWC Purchased Gas Cost of $74,537,396. The Examiners' adjustment is the product of the test year normalized volumes and the average of the Company's gas cost for the nine (9) months up to and including June 2000.[101] As with other adjustments to update test year data in this case, which are proposed by both the Cities and the Company, it is reasonable to update CWC Purchased Gas Cost to reflect the known and measurable increase to gas cost since the test year. It is reasonable to expect that gas cost over the next two years will be higher than test year gas cost. However, the Examiners agree with the Company that using a single month's gas cost poorly represents such a volatile commodity

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[92] *Id.*
[93] Energas' Post-Hearing Brief at p. 37.
[94] Energas' Ex. 4A, Revised Rebuttal Schedule THP-5.
[95] Energas' Post-Hearing Brief at p. 30.
[96] *Id.* at pp. 29-30.
[97] Cities' Ex. 98A, Second Revised Exhibit JP-17.
[98] Cities' Ex. 36.
[99] Cities' Reply Brief at p. 25.
[100] Cities' Ex. 98A, Revised Ex. JP-17.
[101] Energas' Ex. 5, JCC-B, Schedule 2. Cities' Ex. 35. Cities' Ex. 36.

cost.[102] Thus, the Examiners update CWC Purchased Gas Cost using the most recent nine (9) months of gas cost in evidence. In doing so, the Examiners agree with the Cities that use of an historical gas cost, such as that proposed by the Examiners, overcomes any potential decrease in gas consumption due to higher gas cost.[103]

2. REVENUE LAG DAYS

<u>Contested Issue</u>: Should the Revenue Lag Days be 39.51, as proposed by Energas, or decreased to reflect a one-half-day bank lag rather than a one-day bank lag?

<u>Examiners' Recommendation</u>: The Examiners reject the Cities' one-half-day decrease to revenue lag days and support the Company's revenue lag of 39.51 days.

The Company's witness, Mr. Petersen, calculates 39.51 revenue lag days, in which he includes a one-day bank lag. This represents the one-day lag between receiving payment and having funds available to draw on at the bank.[104] The Cities argue that the Company's one day bank lag is based on the assumption that all customers pay by check, the Company made no study of how customers actually pay, and thus bank lag should be reduced to one-half-day.[105]

2.a. Energas' Position

Energas proposes a revenue lag of 39.51 days, which includes a one-day bank lag.[106] The Company argues that Mr. Pous' one-half-day bank lag is not supported by any evidence.[107] The Company claims that the only evidence in the record concerning the proper lag period is Mr. Petersen's testimony. Most customers pay by check.[108] Although customers may pay cash, Energas cannot directly receive such payments, as they are made through third parties.[109] The lag on such third-party payments is comparable to the one-day check lag.[110] Finally, the effect of any direct deposits from larger customers is minimal, given the small number of larger customers in the West Texas service area.[111]

2.b.Cities' Position

The Cities argue that Mr. Pous' one-half-day decrease to revenue lag days is reasonable because Mr. Petersen fails to do a study regarding the methods Energas' customers use to pay their bills.[112] According to the Cities, the record clearly shows the following: 1) Mr. Petersen did not perform a study about payment methods, but rather relied on his assumption that most

[102] Energas' Post-Hearing Brief at p. 30.
[103] Cities' Reply Brief at p. 26.
[104] Energas' Ex. 3 at p. 4.
[105] Cities' Initial Brief at pp. 30-31.
[106] Energas' Ex. 3 at p. 4.
[107] Energas' Post-Hearing Brief at p. 28.
[108] Tr. Vol. 2 at p. 28.
[109] *Id.* at pp. 69-70.
[110] *Id.* at p. 70.
[111] *Id.*
[112] Cities' Reply Brief at p. 23.

customers pay by check;[113] 2) Mr. Petersen did not know if the largest customers paid by direct deposit or wire transfers;[114] 3) Mr. Petersen was uncertain whether the Company takes actions to reduce the one-day bank lag Mr. Petersen just assumed was applicable;[115] and 4) Mr. Petersen wouldn't be surprised to learn there were practices used by other utilities to reduce the one-day revenue lag, but he was unaware of what they may be.[116] According to the Cities, it was not unreasonable for Mr. Pous to adjust the revenue lag days by one-half day to address the Company's failure to consider the various customer payment methods and good cash management practices to reduce the one-day bank lag.[117]

2.c. Examiners' Analysis

The Examiners reject the Cities' one half-day decrease to bank lag and agree with the Company that a one-day bank lag is reasonable. Consequently, the Examiners recommend the Company's revenue lag calculation of 39.51 days. The Company establishes that a one-day bank lag is reasonable, given its customer mix and[118] its knowledge that the majority of its customers pay by check[119] and that cash payments made through third parties result in a similar one-day lag.[120] Mr. Pous' proposed one-half-day bank lag is not supported by the evidence.

3. PAYROLL – PTO LEAD DAYS

<u>Contested Issue</u>: Should the "Payroll-Paid Time Off" Lead Days be 45.90, as proposed by Energas, or 111.74, as proposed by the Cities?

<u>Examiners' Recommendation</u>: The Examiners recommend 45.90 lead days for CWC Payroll PTO.

The parties dispute the appropriate number of lead days to calculate CWC Payroll-Paid Time Off (PTO). The Company proposes 45.90 lead days for CWC Payroll- PTO.[121] The Cities propose 111.74 lead days for CWC Payroll-PTO.[122] Energas' PTO program includes vacation, sick leave, family member illness, and personal business time.[123] The Payroll-PTO lead days calculation requires certain assumptions, including average PTO per employee per year (an undisputed 200 hours), the average amount of PTO per employee carried over from one year to the next, and when PTO is used during the course of the year.[124]

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113 Tr. Vol. 2 at pp. 28-29.
114 *Id.* at p. 29.
115 *Id.* at p. 76.
116 *Id.* at pp. 76-77.
117 Cities' Reply Brief at pp. 24-25.
118 Tr. Vol. 2 at p. 70.
119 *Id.* at p. 78.
120 *Id*.
121 Energas' Ex. 4A, Revised Rebuttal Sch. THP-5.
122 Cities' Second Revised JP-17.
123 Energas' Post-Hearing Brief at p. 4.
124 Energas' Ex. 4 at p. 4.

3.a. Energas' Position

Energas proposes 45.90 lead days for CWC Payroll-PTO.[125] Energas' witness, Mr. Petersen, determines the 45.90 lead days by taking the average of maximum and minimum lead day calculations.[126] Mr. Petersen calculates a maximum 77.80 PTO lead days and a minimum of 14.00 PTO lead days.[127] For his maximum calculation, he assumes that employees will carry 40 hours over from one year to the next, and that employees will use 60 hours during the first half of the year and 100 hours during the second half of the year. For his minimum calculation, he assumes that employees will carry zero hours over from one year to the next, and that employees will use 100 hours during the first half of the year and 100 hours during the second half of the year. Mr. Petersen uses a range of carry over hours to reflect the realistic variations among employees from those who carry over all PTO time to those who use all PTO time during the year it accrues.[128]

The Company's PTO program was implemented in 1999, so historical data on the program is limited. Also, the historical data is unreliable, given that employees were encouraged to postpone vacation and personal business time to help the Company implement its recent customer service initiatives and Oracle system, and to prepare for and be on-call in case of Y2K-related issues.[129] Due to these unusual circumstances, the Company allowed employees to carry over more hours than is normally allowed under the PTO program, *i.e.*, 50 hours rather than 40.[130] The Company's maximum carry over policy is normally 40 hours.[131] The Company argues that, given that employees may use PTO before actually accruing it, with a true-up procedure for those employees who may leave the Company before the end of a year, some employees will use all of their PTO time the year that it accrues. Finally, the Company argues that its assumption that employees will use PTO equally in the first and second halves of the year is reasonable, given that people can be sick, have family members who are sick, have personal business, and take vacation any time of year, not just in the second half of the year.[132]

3.b. Cities' Position

The Cities propose 111.74 lead days for CWC Payroll PTO.[133] Mr. Pous' calculation is based on the following assumptions: First, the average employee will carry over 50 hours of PTO to the next year, based on data provided by the Company to the Cities.[134] Second, the average employee will use 30 hours of PTO during the first half of the year because employees with school age children have little opportunity other than spring break to take vacations during the first half of the year.[135] The average employee will use the remaining 120 hours of PTO

[125] Energas' Ex. 4A, Revised Rebuttal Sch. THP-5.
[126] Energas' Ex. 4 at p. 5.
[127] *Id* at pp. 4-5.
[128] *Id*. at p. 4.
[129] *Id.*
[130] *Id.*
[131] *Id.*
[132] Energas' Post-Hearing Brief at p. 32; Energas' Ex. 4 at p. 4.
[133] Cities' Second Revised JP-17.
[134] Cities' Ex. 14.
[135] Cities' Reply Brief at pp. 27-28.

during the last half of the year because employees with school age children take the majority of time off from school during the second half of the year and when PTO in excess of the carry over amount is about to expire.[136]

3.c. Examiners' Analysis

The Examiners reject the Cities' proposed 111.74 lead days for CWC Payroll PTO and support the Company's proposed 45.90 lead days for CWC Payroll PTO, because the Company's assumptions regarding PTO appear more reasonable than the Cities' assumptions. Mr. Pous assumed that the carryover of PTO days from 1999 is an accurate proxy for estimating carry over days in future years.[137] However, the Company provided exceptions to the PTO policy in 1999 due to the unusual, non-recurring circumstances of allowing employees to carryover 50 hours of PTO, given that employees were encouraged to postpone vacation and personal business time to help the Company implement customer service initiatives and Oracle system, and to prepare for and be on-call in case of Y2K-related issues.[138] Furthermore, Mr. Petersen uses a reasonable range of carry over hours to reflect the variations among employees from those who carry over all PTO time to those who use PTO time during the year it accrues.[139] Thus, the Company's assumption of equal PTO use throughout the year is reasonable, based on its true-up program and the fact that PTO allows time off for many activities other than family vacation.[140]

4. OTHER O & M LEAD DAYS

<u>Contested Issue</u>: Should the "Other O&M" Lead Days be 27.08, as proposed by Energas, or 30.98, as proposed by the Cities?

<u>Examiners' Recommendation</u>: The Examiners recommend 30.98 lead days for CWC "Other O&M".

The calculation of CWC Other O&M is based on when the Company receives a product or service and when the Company pays for that product or service. This payment lead is then subtracted from the collection lag, and the net days are multiplied by the average daily amount of invoices outstanding.[141]

The parties dispute the appropriate number of lead days to calculate CWC Other O&M.[142] Energas proposes 27.08 lead days for CWC Other O&M.[143] The Cities propose 30.98 lead days for CWC Other O&M.[144] The difference between the parties hinges on whether it is

[136] *Id.* at pp. 28, 31.
[137] Energas' Ex. 4 at p. 4.
[138] *Id.*
[139] *Id.*
[140] Energas' Post-Hearing Brief at p. 32.
[141] Energas' Post-Hearing Brief at p. 33.
[142] Cities' Second Revised JP-17. Energas' Ex. 4A, Revised Rebuttal Sch. THP-5.
[143] Energas' Ex. 4A, Revised Rebuttal Sch. THP-5.
[144] Cities' Second Revised JP-17.

reasonable to allow three to five days of mail time for the Company to pay its invoices prior to their latest possible due date.

The Cities' witness, Mr. Pous, recalculated the Company's analysis of an invoice sample, with the most significant change being to assume payment on the 30th day for invoices with 30-day terms where the check was issued by the Company prior to the 30th day.[145] The Company's witness, Mr. Petersen, adopted all of Mr. Pous' suggestions and corrections to the payment lead day calculations, with one exception. Mr. Petersen adjusted Mr. Pous' calculations "allowing 3 business days for mail delivery and handling."[146]

4.a. Energas' Position

The Company proposes 27.08 lead days for CWC Other O&M.[147] As discussed above, Energas' calculation of Other O&M lead days is essentially the same as the Cities, except the Company includes three business days prior to an invoice's due date as part of the payment lead days.

4.b. Cities' Position

The Cities propose 30.98 lead days for CWC Other O&M.[148] The Cities argue that the Commission should use a PUC rule as guidance regarding the calculation of Other O&M lead time.[149] The referenced PUC rule requires utilities to use the later of the actual payment date or the available due date reflected in the invoice. In response to the Company's argument that three business days should be allowed for mailing payments in time to get to the vendors by the due date, the Cities argue that the Company's assertion does not match its actual practice.[150] The Cities provide several examples of invoices where the Company made late payments.[151] In some instances, the Company incurred a late fee. In others, Mr. Petersen was unsure if a late fee was incurred.[152] According to the Cities, it is not reasonable for the Company to reduce Mr. Pous' proposed Other O&M lead days by three to five days, thereby increasing its CWC requirements, on the premise of needing three business days to mail timely payments to their vendors when the record shows that the Company has paid late. Ratepayers already pay any penalties associated with the Company's late payments.[153]
c. Examiners' Analysis

The Examiners agree with the Cities' proposed 30.98 lead days for CWC Other O&M. The Company's requested three-business-day mail time lead is unreasonable, given the evidence that the Company has not always used this mail lead time in the past. Instead, it has paid

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[145] *Id.*
[146] Energas' Ex. 4 at p. 5.
[147] Energas' Ex. 4A, Revised Rebuttal Sch. THP-5.
[148] Cities' Second Revised JP-17.
[149] 16 TEX. ADMIN. CODE § 23.21(d)(2)(B)(iii)(V)(c) (West 1999), *repealed* at 24 Tex. Reg. 1367 (Feb 26, 1999).
[150] Cities' Reply Brief at p. 31.
[151] *Id.* Cities' Ex. 15.
[152] Tr. Vol. 2 at pp. 41-47.
[153] *Id.*

invoices late and in the examples in the record, the Company either incurred a late fee or is not sure if it incurred a late fee.[154]

5. FIT LEAD DAYS

<u>Contested Issue</u>: Should the Federal Income Tax (FIT) Lead Days be 37.80, as proposed by Energas, or 76.14, as proposed by the Cities?

<u>Examiners' Recommendation</u>: The Examiners recommend 76.14 lead days.

The Company proposes 37.80 lead days for CWC Federal Income Taxes (FIT).[155] The Cities propose 76.14 lead days for CWC FIT.[156] CWC FIT lead days are determined by the difference between the midpoint of the tax year and when tax payments are made.[157]

5.a. Energas' Position

Energas proposes 37.80 lead days for CWC FIT.[158] The Company's witness, Mr. Petersen, calculated 37.80 lead days based on four equal quarterly payments, as required by the IRS, with payment made by wire transfer.[159] Mr. Petersen used this normalized payment year instead of actual experience because of the unusual nature of the Company's actual experience.[160] From 1996-1998, there were no quarterly tax payments made by the Company when there was no tax liability or when overpayments were carried forward to subsequent years.[161] Energas argues that, if Mr. Pous' method of using actual tax payments to calculate CWC FIT lead days is applied properly, "the revised lead days will result in an extraordinary increase in CWC, providing a potential windfall to the Company."[162] The Company argues that there is no evidence of poor cash management as alleged by the Cities.[163] Rather, its history of overpayments is a result of "persistently warm weather, the required replacement and extension of distribution plant, and the substantial investments in new technology."[164]

5.b. Cities' Position

The Cities propose a 76.14 lead day period for CWC FIT.[165] The Cities witness, Mr. Pous, uses Energas' average actual quarterly tax payments from 1996-1998 to calculate CWC FIT lead days. The Cities reject the Company's use of hypothetical tax payments instead of actual tax payment information. The Cities point out that the use of actual payments has been

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[154] *Id.*
[155] Energas' Ex. 3 at p. 6.
[156] Cities' Ex. 98A, Revised Ex. JP-17.
[157] Energas' Ex. 3 at p. 6.
[158] *Id.*
[159] *Id.*
[160] Energas' Post-Hearing Brief at p. 34.
[161] Energas' Ex. 4 at p. 6; Energas' Ex. 48.
[162] Energas' Reply Brief at p. 24.
[163] *Id.* at p. 25.
[164] *Id.* at p. 25; Energas' Ex. 2 at pp. 3-4.
[165] Cities' Initial Brief at p. 27.

adopted by the Public Utility Commission of Texas.[166] The Cities also note that, in GUD No. 8976 before the Railroad Commission of Texas, the Examiner recommended the rejection of the use of hypothetical tax payments.[167] Also, the Cities believe that Energas failed to meet its burden of proof of providing a specific explanation as to why the overpayment is not the result of poor money management.[168]

5.c. Examiners' Analysis

The Examiners recommend rejection of the use of hypothetical tax payments, as proposed by the Company. The use of actual payments is more reasonable, and has been approved by the PUC and has been recommended by a Railroad Commission Examiner.[169] The Examiners find that the Company failed to meet its burden of proof to provide a specific explanation as to why the overpayments were not the result of poor money management. If, as the Company argues, Mr. Pous erred when using actual tax payments to calculate CWC FIT lead days, it should have provided the proper actual tax payment calculation and result in its testimony. In the absence of this evidence, the Examiners recommend 76.14 lead days for CWC FIT.

6. LEAD DAYS FOR TAXES OTHER THAN FIT

<u>Contested Issue</u>: Should lead days for Taxes Other Than FIT be 80.00, as proposed by Energas, or 117.13 as proposed by the Cities?

<u>Examiners' Recommendation</u>: The Examiners recommend 80.00 lead days for CWC Taxes Other Than FIT.

The Company proposes 80.00 lead days for CWC Taxes Other Than Federal Income Taxes (Other Taxes).[170] The Cities propose a 117.13 lead day period for Other Taxes.[171] CWC Other Taxes lead days are determined by the net lead-lag days involved per kind of tax.[172] The parties disagree on whether to include prepaid taxes (Prepaid State Gross Receipts tax and Prepaid Corporate Franchise tax) in the lead day calculation.

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166 Tex. Publ. Util. Comm'n., *Application of Central Power and Light Company for Authority to Change Rates,* PUC Docket No. 14965, 176 P.U.R. 4th 397 (1997).
167 Tex. R.R. Comm'n, *Statement of Intent to Change the City-Gate Rate of TXU Lone Star Pipeline, Formerly Known as Lone Star Pipeline Co., Established in GUD No. 8664,* Gas Utilities Docket (GUD) No. 8976, (Proposal For Decision at p. 50).
168 Cities' Initial Brief at p. 29.
169 Tex. Publ. Util. Comm'n, *Application of Central Power and Light Company for Authority to Change Rates,* PUC Docket No. 14965, 176 P.U.R. 4th 397 (1997); Tex. R.R. Comm'n, GUD No. 8976, Proposal For Decision at p. 50.
170 Energas' Ex. 4A, Revised Rebuttal Schedule THP-5.
171 Cities' Reply Brief, Attachment A, Second Revised Exhibit JP-17.
172 Energas' Ex. 4 at pp. 6-7.

6.a. Energas' Position

The Company proposes 80.00 lead days for CWC Other Taxes.[173] The Company's witness, Mr. Petersen, includes prepaid taxes in the calculation. He argues that this is appropriate because, in the overall CWC calculation, the lead days are applied to the total dollar value of Other Taxes in his overall CWC calculation.[174] This total dollar value includes the amount of prepaid taxes.[175] In response to Mr. Pous' apparent exclusion of prepaid taxes from his lead day calculation, the Company argues that these adjustments are unfounded and unexplained in Mr. Pous' testimony.[176]

6.b. Cities' Position

The Cities propose 117.13 lead days for CWC Other Taxes.[177] The Cities' witness, Mr. Pous, excludes prepaid taxes from his lead day calculation but includes them in the dollar value of Other Taxes in his overall CWC calculation.[178]

6.c. Examiners' Analysis

The Examiners recommend 80.00 lead days for CWC Other Taxes and reject the Cities' proposed calculation. The inconsistency in Mr. Pous' calculation is apparent and was noted by Mr. Petersen in his rebuttal and by the Company in its Post-Hearing Brief.[179] The Cities fail to adequately explain and support Mr. Pous' exclusion of prepaid taxes from his Other Taxes lead day calculation.

V. RATE OF RETURN

As part of this proceeding the Commission must establish a reasonable rate of return for the Applicant. In establishing a gas utility's rates, the regulatory authority shall establish the utility's overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.[180] The regulatory authority may not establish a rate that yields more than a fair return on the adjusted value of the invested capital used and useful in providing service to the public.[181]

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[173] Energas' Ex. 4A, Revised Rebuttal Schedule THP-5.
[174] Energas' Ex. 4 at p. 7.
[175] Energas' Ex. 4A, Revised Rebuttal Schedule THP-5.
[176] Energas' Post-Hearing Brief at p. 36.
[177] Cities' Reply Brief, Attachment A, Second Revised Exhibit JP-17.
[178] *Id.*
[179] Energas' Ex. 4 at p. 7., Energas' Post-Hearing Brief at p. 36.
[180] TEX. UTIL. CODE ANN. § 104.051 (Vernon 1998).
[181] TEX. UTIL. CODE ANN. § 104.052 (Vernon 1998).

A utility's return on its investment is a product of the rate base multiplied by a fair rate of return.[182] Thus, having established a rate base, the next task for the Commission is to determine a suitable rate of return.[183] The rate of return is the amount of money that a utility is allowed an opportunity to earn, over and above operating expenses, depreciation, and taxes.[184] As noted by the court in *Railroad Commission of Texas v. Lone Star Gas Company*, to achieve the rate of return that a utility should be allowed to earn, the regulatory agency considers the cost to the utility of its capital expressed as follows: 1) interest on long-term debt; 2) dividends on preferred stock; and 3) earnings on common stock.[185] In this case, the applicant has substituted the interest on short-term debt for dividends on preferred stock.

Contested Issue: What cost of equity and overall rate of return should be set for Energas in this case?

Examiners' Recommendation: The Examiners recommend a 12.20 percent cost of equity, and a 9.87 percent overall rate of return.

A. ENERGAS' POSITION

Energas requests an overall rate of return of 10.02 percent. This rate of return is based on capital structure ratios of 41.29 percent long-term debt, 10.54 percent short-term debt, and 48.17 percent common equity. Energas' recommended cost of long-term debt and short-term debt of 8.06 percent and 6.35 percent, respectively, are Atmos' average costs of debt as of December 31, 1999,[186] and are uncontested.[187] Finally, Energas requests a rate of return on common equity of 12.50 percent.

Energas' rate of return recommendation is presented by Dr. Donald A. Murry. Dr. Murry bases the capital structure ratio for Energas on the capital structure of Energas' parent Company, Atmos Energy Corporation, Inc. Dr. Murry uses the equity ratios of a group of six publicly traded Local Distribution Companies (LDCs) for comparison purposes.[188] Dr. Murry selects his recommended cost of common equity from a 12.25 percent to 12.75 percent range, which is based on the results of two methods of analysis -- the constant growth discounted cash flow (DCF) method and the capital asset pricing model (CAPM), a risk premium analysis.

Dr. Murry's DCF analysis produces an average cost of equity range for Atmos of 12.68 percent to 15.25 percent.[189] The DCF analysis for the group of six comparable LDCs produces an average cost of equity range of 9.25 percent to 10.60 percent.[190] Dr. Murry's risk premium

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[182] *Railroad Commission of Texas v. Lone Star Gas Company*, 599 S.W.2d 659 (Tex. App.—Austin 1980).
[183] *Id.*
[184] *Id.*
[185] *Id.*
[186] Energas' Ex. 10 at page 8, lines 6-13.
[187] Energas' Post-Hearing Brief at p. 39.
[188] Energas' Ex. 10, Sch. DAM-4.
[189] *Id.*, Schedules DAM 6-11.
[190] *Id.*, Schedules DAM 6-11.

analysis (CAPM) produces a cost of equity range for Atmos of 12.31 percent to 12.84 percent.[191] The risk premium analysis (CAPM) for the group of six comparable LDCs produces an average cost of equity range of 12.51 percent to 13.30 percent.[192]

While Dr. Murry uses both a DCF analysis and a risk premium analysis to calculate the cost of equity for the six comparable LDCs, he chooses not to mathematically combine these results with his results for Atmos alone, as Mr. Lawton does. In Dr. Murry's opinion, averaging the DCF results of Atmos with the DCF results of the six comparable LDCs is not appropriate.[193] Rather, Dr. Murry uses the average DCF and risk premium results of the six comparable LDCs as a basis for comparison, or "floor," for his estimate of Atmos' cost of equity.[194]

On rebuttal, Dr. Murry updates his cost of equity analysis to reflect the most recent financial data and conditions available at the time of the hearing, following the same analytical process as in his direct testimony. His updated cost of equity recommendation remaines at 12.50 percent, unchanged from his direct testimony. The updated DCF analysis produces an average cost of equity range of 11.83 percent to 14.30 percent.[195] The updated DCF analysis for the group of six comparable LDCs produces an average cost of equity range of 9.65 percent to 10.89 percent.[196] The risk premium analysis is also updated and results in a range of 11.11 percent to 12.90 percent.[197] The updated risk premium analysis for the group of six comparable LDCs produces an average cost of equity range of 11.55 percent to 13.54 percent.[198]

Table 1 is a summary of the analysis conducted by Dr. Murry. Column A is the Capital Structure: Long-Term Debt, Short-Term Debt, and Common Equity. Column B is the cost of each element of the capital structure. Column C is the method applied by Dr. Murry to calculate the cost of each element of capital structure.

Table 1 - Summary of Energas' Rate of Return Analysis

Column A Capital Structure		Column B Cost of Capital	Column C Method for Calculating Cost of Capital	
Long-Term Debt	41.29%	8.06%	Average Cost of Atmos Long-Term Debt	
Short-Term Debt	10.54%	6.35%	Average Cost of Atmos Short-Term Debt	
Common Equity	48.17%	12.50%	Initial Analysis: 1. Constant DCF Atmos: 12.68-15.25% LDC's: 9.25-10.60% 2. CAPM (risk premium) Atmos: 12.31-12.84% LDC's: 12.51-13.30%	Updated Analysis: 1. Constant DCF Atmos: 11.83-14.30% LDC's: 9.65-10.89% 2. CAPM (risk premium) Atmos: 11.11-12.90% LDC's: 11.55-13.54%

191 *Id*., Schedules DAM 13-14.
192 *Id*., Schedules DAM 13-14.
193 Tr. Vol. 4 at page 89.
194 *Id*. at page 74.
195 Energas' Ex. 49, Schedules DAM 6-11.
196 Energas' Ex. 49, Schedules DAM 6-11.
197 Energas' Ex. 50, Schedules DAM 13-14.
198 Energas' Ex. 50, Schedules DAM 13-14.

B. CITIES' POSITION

The Aligned Cities recommend an overall rate of return of 9.39 percent. The Aligned Cities agree to Energas' proposed capital structure, cost of long-term debt, and cost of short-term debt. However, they dispute Energas' cost of equity recommendation of 12.50 percent, instead recommending a cost of equity of 11.20 percent. Mr. Daniel Lawton, the witness for the Aligned Cities, arrives at that figure by performing two types of Discounted Cash Flow (DCF) analyses: Constant Growth DCF and Non-Constant Growth DCF. Mr. Lawton chooses to average the results of his DCF analyses for Atmos with his results for each of the six comparable LDCs, giving equal weight to the results for each of seven LDCs. Since the results for Atmos are higher than any of the six comparable LDCs in most cases, Mr. Lawton's overall average of results provides a lower final estimate of cost of equity.

Mr. Lawton's Constant Growth DCF analysis produces an average cost of equity of 12.92 percent for Atmos only, 10.57 percent for the six comparable LDCs, and 10.91 percent for the average of Atmos and the six comparable LDCs. The Non-Constant Growth DCF analysis produces an average cost of equity of 9.70 percent for Atmos only, 13.06 percent for the six comparable LDCs, and 11.38 percent for the average of Atmos and the six comparable LDCs. In his rebuttal, Dr. Murry shows that the Price/Earnings (P/E) ratio, a significant input of Mr. Lawton's Non-Constant DCF analysis for Atmos, was inappropriate.[199] Dr. Murry also disputes the appropriateness of Mr. Lawton's Non-Constant DCF analysis for estimating the cost of equity because it is a method more commonly associated with estimating the cost of debt.[200] Nonetheless, Dr. Murry provides for Mr. Lawton a corrected and updated Non-Constant DCF calculation, which results in an average cost of equity of 13.89 percent for Atmos only, 11.74 percent for the six comparable LDCs, and 12.81 percent for the average of Atmos and the six comparable LDCs.[201] Dr. Murry's updated Non-Constant DCF results are included in Table 2 with Mr. Lawton's other analyses.

Mr. Lawton's updated Constant DCF analysis results in an average cost of equity of 11.70 percent for Atmos only, 10.27 percent for the six comparable LDCs, and 10.48 percent for the average of Atmos and the six comparable LDCs.[202]

The Aligned Cities argue in their Reply Brief that Atmos' cost of equity is higher than the six comparable LDCs because of Atmos' undisputed strategy of growth through acquisition. Thus, Mr. Lawton average the cost of equity for the six comparable LDCs with Atmos' cost of equity, thereby lowering his final estimate of Energas' cost of equity.

[199] Energas' Ex. 51 at pp. 1-5. Tr., Vol. 9 at pages 104-108. (A P/E ratio of 8.59% was used rather than an arguably more appropriate P/E ratio of 14.00%; using the lower P/E ratio resulted in a lower cost of equity result for Mr. Lawton's non-constant DCF analysis for Atmos.)
[200] Energas' Ex. 11 at p. 5.
[201] Energas' Ex. 51 at pp. 6-10.
[202] Energas' Ex. 52 at p. 1.

Table 2 is a summary of the analysis conducted by Mr. Lawton.

Table 2 - Summary of Aligned Cities' Rate of Return Analysis

Column A Capital Structure		Column B Cost of Capital	Column C Method for Calculating Cost of Capital	
Long-Term Debt	41.29%	8.06%	Average Cost of Atmos Long-Term Debt	
Short-Term Debt	10.54%	6.35%	Average Cost of Atmos Short-Term Debt	
Common Equity	48.17%	11.20%	Initial Analysis: 1. Constant DCF Atmos 12.92% LDC's 10.57% Avg. 10.91% 2. Non-Constant DCF Atmos 9.70% LDC's 13.06% Avg. 11.38%	Updated Analysis: 1. Constant DCF Atmos 11.70% LDC's 10.27% Avg. 10.48% 2. Non-Constant DCF Atmos 13.89% LDC's 11.74% Avg. 12.81%

C. EXAMINERS' ANALYSIS

The Examiners recommend and consider to be reasonable a 12.20 percent cost of equity. Energas' requested 12.50 percent cost of equity has been adjusted downward by 30 basis points in order to: 1) reflect both Dr. Murry's and Mr. Lawton's updated Constant DCF calculations, which are lower than the original results; and 2) to give greater weight to the cost of equity estimates for the six comparable LDCs, which are all lower than the cost of equity estimates for Atmos alone.

First, the cost of equity results from the updated Constant DCF calculations provided by both Dr. Murry and Mr. Lawton at the hearing decrease significantly from the cost of equity results calculated by these two witnesses in their direct testimony. The witnesses' updated results are based on the most recent available financial information and reflect known and measurable changes to their results presented in direct testimony.

As shown on Examiners' Schedule E-3, *Examiners' Summary of Parties' Cost of Equity Results*, the results of four out of six of Dr. Murry's Constant DCF analyses decrease when updated with more recent financial data. The average of the results from all six of Dr. Murry's Constant DCF analyses decrease by 90 basis points after being updated. In like manner, the results of four out of four of Mr. Lawton's Constant DCF analyses for Atmos decrease when updated. The average of the results from all four of Mr. Lawton's Constant DCF analyses decrease by 122 basis points after he updated them.

Second, the Examiners give more weight to the six comparable LDCs in estimating Energas' cost of equity than did Dr. Murry, because 1) the six comparable LDCs are Atmos' peers and competitors in the capital marketplace; and 2) their cost of equity estimates exclude the effects of Atmos' strategy of growth through acquisition. As shown on Examiners' Schedule E-3, the cost of equity for the six comparable LDCs in every Constant DCF calculation by both Dr.

Murry and Mr. Lawton is significantly less than the cost of equity results for Atmos, alone. The average cost of equity for the six comparable LDCs resulting from the Constant DCF calculations in Dr. Murry's direct testimony is 405 basis points lower than the average cost of equity for Atmos. The average cost of equity for the six comparable LDCs resulting from the Constant DCF calculations in Dr. Murry's updated calculations is 280 basis points lower than the average cost of equity for Atmos. The average cost of equity for the six comparable LDCs resulting from the Constant DCF calculations in Mr. Lawton's direct testimony is 235 basis points lower than the average cost of equity for Atmos. The average cost of equity for the six comparable LDCs resulting from the Constant DCF calculations in Mr. Lawton's updated calculations is 143 basis points lower than the average cost of equity for Atmos.

The Examiners do not average Atmos' estimated cost of equity with the six comparable LDC's in order to arrive at Energas' cost of equity, as does Mr. Lawton. Rather, 12.20 percent represents a reasonable estimate that takes into account the lower costs of equity of the six comparable LDCs.

The Examiners believe that it is both reasonable and prudent to reduce Dr. Murry's recommended cost of equity to 12.20 percent in order to reflect the weight of the evidence regarding the cost of equity of Atmos' peers and competitors in the capital marketplace. Given the Examiners' recommended cost of equity of 12.20 percent, the Examiners recommend an overall rate of return of 9.87 percent. The calculation is shown in Table 3 below.

Table 3 - Examiners Recommended Rate of Return

	Capital Ratio	Cost Rate	Weighted Avg Cost
Long-Term Debt	41.29%	8.06%	3.33%
Short-Term Debt	10.54%	6.35%	0.67%
Common Equity	48.17%	**12.20%**	5.88%
Total	100.0%		**9.87%**

VI. REVENUES AND EXPENSES

A. REVENUES

Energas' appropriate normalized test year revenue at present rates is $45,701,207. As shown in the sections below, the parties disagree on the appropriate weather normalization and customer growth adjustments, and the Examiners recommend that the Commission approve Energas' revenue proposals. In addition, the parties have agreed on adjustments to Energas' initial test year revenue request for revenues received for transportation on the Lubbock Power and Light Transportation Line and for revenues from the additional rents received from subleased office space. With these two agreed adjustments, Energas' appropriate normalized test year revenue is decreased from Energas' original request of $45,743,592 to $45,701,207.

1. Weather Normalization

Test year gas sales adjustments and the associated impact on test year revenues are commonly made in rate cases to recognize the net effect of weather during the test period. The purpose of a weather normalization adjustment is to normalize test year volumes and revenues to reflect normal weather conditions.[203]

Weather adjustments (normalization) are typically computed by comparing the actual number of heating degree-days to normal levels of heating degree-days.[204] When weather is colder than normal (actual heating degree-days exceed normal heating degree-days), test year gas sales and revenues will exceed expected gas sales and expected revenues under normal weather conditions.[205] The converse of this situation (warmer than normal weather) requires an increase in sales and revenues to normalize the test year data.[206]

It is undisputed in this case that test year volumes and revenues were understated due to warmer then normal weather conditions. It is also undisputed that adjusted (lagged) actual heating degree-days were 2,752 and normal heating degree-days were 3,294 during the test year.[207] The parties disagree regarding the magnitude of this adjustment.

Contested Issue: **Should Energas' Weather Normalization Adjustment be approved?**

Examiners' Recommendation: **Yes. The Examiners recommend approval of the Applicant's proposed weather normalization adjustment of 2,668,208 Mcf.**

1.a. Energas' Position

Energas proposes a weather normalization adjustment of 2,668,208 Mcf.[208] This increases its test year revenue by approximately $2,632,196.[209] Energas relies on the weather normalization calculation described in the Railroad Commission of Texas' *Natural Gas Rate Review Handbook* to calculate its weather normalization adjustment. The Applicant summarizes the calculation as follows:[210]

$$\frac{WeatherSensitiveVolumes}{ActualDegreeDays} \times NormalDegreeDays + BaseLoadVolumes$$

[203] Cities' Ex. 91 at p. 17.
[204] *Id*. at p. 18.
[205] *Id.*
[206] *Id.*
[207] Cities' Ex. 91, Schedule DJL-8.
[208] Energas' Ex. 5, JCC-C, WP 2-2 through WP 2-7.
[209] Cities' Initial Brief at p. 39.
[210] Energas' Ex. 5 at p. 8.

Where, *Base Load Volumes* are estimated as August volumes times twelve, and *Weather Sensitive Volumes* are *Total Volumes* minus *Base Load Volumes.* Volume amounts utilized are per customer volumes. This negates variations due to Seasonal Customers. Mr. Cagle provides detailed calculations to determine the appropriate adjustment to revenue for weather normalization.[211]

1.b. Cities' Position

The Cities argue that the Company's weather adjustment should increase test year revenues by $2,696,461, a $64,266 difference. The Cities' witness, Mr. Lawton, originally calculated the Company's weather normalization adjustment on a monthly basis, and argues that Mr. Cagle's calculation is theoretically inconsistent in that in about 41 percent of the months, a theoretically impossible result is generated.[212] Mr. Lawton later annualized his calculation, and presented a new recommendation at the hearing that still reflects a $64,266 difference from Energas' proposal.

1.c. Examiners' Analysis

The Examiners recommend that the Company's weather normalization calculation and adjustment be accepted without modification. This is due to the Company's adherence to Railroad Commission of Texas guidelines with respect to its calculation and the Cities' failure to adequately support its argument.

At the hearing, Mr. Lawton admitted his error of calculating weather normalization on a monthly basis instead of on an annual basis, which reduced, but did not eliminate the difference between his recommendation and Mr. Cagle's:

> I went back and looked at that and annualized it rather than putting it on a monthly basis, consistent with the way the Railroad Commission does it in their . . . assistance package for cities, and looked again at the recent TXU case and it also was annualized. I did it on a monthly basis. And this reduced the differences between us and the Company.[213]

Nonetheless, Energas is correct that Mr. Lawton fails to provide sufficient supporting documentation for the Cities' calculation to determine the source of the difference between its and the Company's recommendations. Energas points out that Mr. Lawton did not submit revised calculations to show that he accounted "for changes in the number of customers from month-to-month,"[214] consistent with weather normalization theory.[215] Therefore, the Examiners used Mr. Cagle's weather normalization adjustment.

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[211] Energas' Ex. 5 at WP 2-2 GS; Energas' Ex. 5A at p. 19, ln. 17 – p. 23, ln. 11.
[212] Cities' Ex. 91 at p. 18.
[213] Tr. Vol. 6 at p. 171.
[214] Energas' Ex. 6 at p. 20, lns. 4-6.
[215] *Id.*; Energas' Ex. JCC-3 (Natural Gas Rate Review Handbook); Energas' Reply Brief at p. 35.

2. Customer Growth Adjustment

The customer growth adjustment is intended to normalize revenues for customer growth "to show a full year's billing for all customers receiving service at the end of the test year."[216] When the Company experiences growth in customers during the test year, test year gas sales and revenues will be understated and will require an adjustment to increase sales and revenues to normalize the test year data. The converse of this situation (a decrease in customers during the test year) requires an adjustment to decrease sales and revenues to normalize the test year data. It is undisputed in this case that test year volumes and revenues were understated due to customer growth during the test year and require an adjustment to increase volumes and revenues to normalize the test year data. The parties disagree regarding the magnitude of this adjustment.

Contested Issue: **Should Energas' Customer Growth Adjustment be approved?**

Examiners' Recommendation: **Yes. The Examiners recommend approval of the Applicant's proposed customer growth adjustment to increase volumes by 32,849 Mcf.**

2.a. Energas' Position

Energas proposes a customer growth adjustment of 32,849 Mcf, which results in a $90,332 increase to revenue at present rates.[217] The Company's adjustment reflects the average increase in customers throughout the test year and assumes that new customers are added evenly throughout the year.[218] "Mathematically, this requires an adjustment upwards equivalent to including one half of the new customers in the test year, because on average, the new customers are already included for approximately half a year."[219]

2.b. Cities' Position

The Cities argue that the customer growth adjustment should be twice the size of the Company's proposed adjustment to reflect a full year's billing for all customers receiving service at the end of the test year.[220] According to the Cities, using one-half the customer growth fails to capture the customer levels on the system when rates will be in effect in this case.[221]

2.c. Examiners' Analysis

The Examiners recommend that the Company's customer growth calculation and adjustment be accepted without modification. As the Company argues, the revenue from one-half of the new customers in the test year is already included in the test year revenue. The

[216] Cities' Initial Brief at p. 40.
[217] Energas' Ex. 5, WP 2-9, Sch. 2. The $90,332 increase to revenue was determined by subtracting the number of customers and Mcf numbers found in Column (b) of WP 2-9 from Column (d) on Schedule 2.
[218] Energas' Ex. 6 at p. 18.
[219] Energas' Reply Brief at p. 36.
[220] Cities' Initial Brief at p. 40.
[221] *Id.*

methodology proposed by the Cities double counts this revenue and results in a customer growth adjustment that is twice as large as it should be.

3. LUBBOCK POWER AND LIGHT TRANSPORTATION REVENUE

The Examiners recommend that $120,000 in revenues received for transportation on the Lubbock Power and Light Transportation Line be excluded from the Company's normalized test year revenue. The parties are in agreement that this is the appropriate adjustment since the costs of constructing and operating the Lubbock Power and Light Transportation Line were similarly excluded from the Company's request in these proceedings.[222]

4. OTHER REVENUES, RENTAL INCOME[223]

The Examiners recommend that $77,615 in revenues from the additional rents received from subleased office space be included in the Company's normalized test year revenue.[224] The parties are in agreement that this is the appropriate adjustment to reflect the rental revenue from office space that was sublet for only a portion of the test year. The Company plans to continue subleasing all of this office space in the future.[225]

B. EXPENSES

1. DEPRECIATION

Texas Utilities Code Section 104.054 requires the Commission to establish proper and adequate rates and methods of depreciation for each class of property of a gas utility.[226] Depreciation attempts to measure the use of assets and allow the recovery of their costs over their service lives. According to Energas' witness Mr. Donald S. Roff, the most widely recognized accounting definition of depreciation is that of the American Institute of Certified Public Accountants, which states:

Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.[227] The FERC definition for depreciation in 18 Code of Federal Regulations (CFR), Part 201 states:

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[222] Energas' Post-Hearing Brief at p. 50. Cities' Initial Brief at pp. 40-41.
[223] This adjustment was referred to in Mr. Burman's rebuttal and the Cities' Reply Brief as "Rent Expense." However, since the parties treat it as an adjustment to normalize test year revenue, it is included in the revenue section of the Examiners' Proposal for Decision.
[224] Cities' Ex. 98 at p. 76.
[225] *Id.*

[226] TEX. UTIL. CODE ANN. § 104.054(a) (Vernon 1998).
[227] Energas' Ex. 18 at p. 4, lns. 14-20.

> "Depreciation," as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[228]

Annual depreciation expense is determined by establishing the value of the property (plus cost of removal, less salvage value), estimating the service life, or survivor curve, over which the value of the property is written off, then distributing the value of the property over this time span as an expense.

Energas' requested annual depreciation expense is $7,895,888. The Cities recommend an annual depreciation expense of $3,346,858. The Examiners recommend an annual depreciation expense of $4,857,698. The Applicant and Aligned Cities disagree about the calculation procedure, service lives in four accounts, and the appropriate amount of net salvage for mains and all other distribution plant, as discussed in the following sections. They also disagree on how to treat third party reimbursements and fully accrued accounts.

1.a. Calculation Procedure: Equal Life Group (ELG) v. Average Life Group (ALG)

Energas presented a depreciation study by Mr. Donald S. Roff, which uses the ELG calculation procedure to reach its requested depreciation rate, and requests that the Commission approve its use for Energas for the first time. The Cities argue that ELG-based depreciation rates increase depreciation expense by over one million dollars above ALG-based depreciation rates,[229] and recommend using the ALG-based depreciation calculation performed by Mr. Jack Pous instead. The Examiners recommend using the ALG calculation procedure because it will result in more just and reasonable rates into the future than the ELG procedure. The significant issues raised by the Cities are addressed below.

1.a.(1) Availability of Historical Data and Detailed Facilities Information

Contested Issue: **Whether ELG is inappropriate in this case due to limited historical data and detailed information about the assets underlying the life estimation process**

Examiners Recommendation: **The limited amount of historical data and lack of detailed facilities information makes the use of the ELG methodology inappropriate in this case.**

[228] Cities' Ex. 98 at p. 4, lns. 20-28.
[229] Cities' Ex. 98 at p. 44.

1.a.(1)(a) Energas' Position

Energas takes issue with the Cities' claim that Energas has not adequately predicted future retirements because of a lack of historical data. Energas argues that eleven years of historical data is used in performing the life analyses for the various accounts, which, as Mr. Roff testified, occurs independently of the ELG calculation[230]

Energas further argues that the only influence that more data might have on the analysis is the selection of a different survivor curve. For instance, in accounts like 399.86, *PC Hardware*, where the account is new and the data sparse, there may be more judgment in selecting an Iowa curve. However, if the survivor curve is wrong, argues Energas, then ALG rates will be as wrong as ELG rates.[231] In essence, then, Energas argues that, because the selection of the survivor curves is separate from the calculation method, the Cities' proposed ALG method remains less accurate than ELG because it only uses an average service life for an entire category, rather than equal life groups.

1.a.(1)(b) Cities' Position

The Cities argue that the ELG procedure is too sensitive to be accurate with Energas' very limited data and guesswork that was used to support the historical life analysis and to establish life and dispersion curve combinations. The Cities cite NARUC guidelines:

> [T]he "*ELG procedure is more sensitive* than VG [ALG] to retirement dispersion curves. Therefore, in order to calculate accurate depreciation accruals using the ELG procedure, detailed vintage plant mortality data must be maintained from which future mortality dispersion can be estimated. *Without the long-term accumulation of data involving large numbers of units within each group, such accuracy may not be obtainable*."[232]

Even the Public Utility Commission of Texas has recognized this downfall of the ELG procedure when it required a utility to switch from ELG to ALG:

> Because its theoretical superiority requires so many accurate predictions about future events, *which are difficult if not impossible to achieve*, the Judges conclude that depreciation rates based on ELG are as, but no more accurate than those based on ALG. . . .[233]

Further, the Cities point out that any inaccuracies in determining life and dispersion curves are exaggerated through the ELG procedure. The Cities provide examples that demonstrate that the

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[230] Tr. Vol. 9 at pp. 42-43.
[231] Tr. Vol. 9 at p. 44, lns. 7-11.
[232] Cities' Ex. 88 at p. 165.
[233] Cities' Ex. 105 at p. 211; Tex. Publ. Util. Comm'n, *Application of Central Power and Light Co. for Authority to Change Rates*, Docket No. 14965, Proposal for Decision at p. 211.

slightest change in the dispersion pattern can have a measurable impact in the resulting ELG depreciation rate.[234]

Thus, the Cities argue that, while ELG is theoretically more accurate, in actual practice it is impractical and can easily result in an unreasonably high amount of depreciation if the life and dispersion curves do not exactly match the actual service lives of the assets. The ALG procedure, on the other hand, "recognizes the tremendous level of averaging and estimations that are employed in the life portion of the depreciation analysis to arrive at an assumed life-curve combination applicable to all remaining investment."[235] The ALG procedure is not subject to the same sensitivity associated with the variance in dispersion patterns as is the ELG procedure.

Further, the Cities cite other agencies that have recognized the difficulties caused by ELG due to the necessity of accurately predicting future retirements, and their decisions that ELG should not be used "without the detailed records necessary to make reasonably accurate estimates of future mortality dispersions:"[236]

> Depreciation rate changes are inherent in ELG and not in ALG. This would place a tremendous burden upon the commission to determine annually whether or not such changes would require modifications in Southwestern's overall rates to consumers.[237]

In like manner, the Cities point out a Louisiana Public Service Commission's rejection of Mr. Roff's recommended use of ELG:

> ELG provides accelerated recovery, higher depreciation recovery in the early years and even though, if carried out correctly, it should decrease in the subsequent years, the testimony of EGSI's own witness, Mr. Roff, shows that under EGSI's depreciation study, the rates would remain constant at the higher figure.[238]

The Cities contrast these cases with the TXU Lone Star Pipeline case, GUD No. 8976, which is the only gas utility in Texas that has been allowed to use the ELG procedure. The Cities point out that TXU Lone Star had 38 years of age data, compared to Energas' mere 11 years of historical data.[239] The Cities also point out that TXU Lone Star had detailed information about the type of pipe, where Energas' witness Mr. Roff did not have this information. Therefore, the Cities argue that ELG is inappropriate in this case because of Energas' lack of historical data.

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[234] Cities' Initial Brief at pp. 45-48.
[235] Cities' Initial Brief at p. 44.
[236] *Southwestern Public Service Company,* Case No. 1435, 27 PUR 4th 302, 317 (New Mexico PSC 1978).
[237] *Id.* at 318.
[238] *Entergy Gulf States, Inc.*, Docket No. U-22092, 184 PUR 4th 540, 553 (La. PSC 1998).
[239] Cities' Initial Brief at p. 53; Tr. Vol. 8 at pp. 64-65.

1.a.(1)(c) Examiners' Analysis

The Examiners agree with the Cities that Energas' lack of significant historical data and detailed information make the use of ELG inappropriate because of inaccuracies in the survivor curves. This conclusion is consistent with decisions by other regulatory agencies that have recognized the necessity for detailed information when using ELG.[240]

The Examiners find it significant that Energas has only 11 years of historical data on which to rely. Even Energas' witness Mr. Roff agreed that the performance of a depreciation study is a function of the available data, and that he could not identify another single Company for which a depreciation study was based on less than 10 years worth of data.[241] This is especially troubling in light of the large amount of recent information technology investment that Energas is attempting to depreciate under the ELG procedure, with extremely limited or nonexistent historical data. The difficulty in determining accurate service lives for information technology investments is further demonstrated in the sections below concerning the determination of the survivor curves for some accounts. Therefore, the Examiners agree with the Cities that "Mr. Roff's extreme reliance on unsubstantiated guesswork in the evaluation phase of his study reinforces the concern noted by NARUC[242] pertaining to the accuracy of the life analysis if an ELG calculation procedure is contemplated."[243]

In addition, the Examiners agree with the Cities that TXU Lone Star's use of ELG does not provide an example that must be followed, because TXU Lone Star had a far greater amount of historical data. As the Cities point out, TXU Lone Star had 38 years of historical data on which to rely, while Energas has eleven years of data.[244] Other key distinguishing factors are knowledge of the type of property retired, the type of property subject to new depreciation rates, and the pressure differentials reflected on the two different types of systems. The Cities showed that Mr. Roff did not have accurate information about the type of pipe that Energas has in the ground – whether the pipe is bare steel, cathodically protected steel, cast iron pipe, or plastic, much less which type of plastic.[245] Due to pressure considerations, pipeline companies do not have a lot of plastic pipe investment.[246] Furthermore, TXU Lone Star had long-term age mortality data for its primarily steel pipe system, while Energas has far less data concerning its system, which has more plastic pipe. Therefore, the Examiners agree with the Cities that the use of ELG methodology made more sense in the TXU Lone Star than it does in this case because of the amount and type of historical data involved. In this case, the historical and detailed information is simply not substantial enough to support Energas' use of the ELG calculation method.

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[240] *Southwestern Public Service Company*, Case No. 1435, 27 PUR 4th 302, 317 (New Mexico PSC 1978). Cities' Reply Brief at p. 52; *Entergy Gulf States, Inc.*, Docket No. U-22092, 184 PUR 4th 540, 553 (La. PSC 1998); Tex. Publ. Util. Comm'n, *Application of Central Power and Light Co. for Authority to Change Rates*, Docket No. 14965, Proposal for Decision at p. 211. (Cities' Ex. 105 at p. 211).
[241] Tr. Vol. 5 at p. 25.
[242] Cities' Ex. 88 at p. 165.
[243] Cities' Initial Brief at p. 52.
[244] Tr. Vol. 8 at pp. 64-65.
[245] Tr. Vol. 8 at pp. 64-65; Tr. Vol. 6 at pp. 47-49.
[246] Tr. Vol. 8 at p. 66.

1.a.(2) *Accuracy of Estimates and Time Sensitivity*

Contested Issue: **Does the sensitivity of the ELG methodology to time and accuracy of estimates weigh against its use in this case?**

Examiner' Recommendation: **Given the sensitivity of the ELG methodology to estimates made early in the lives of assets, the ELG methodology is inappropriate for setting rates in this case.**

1.a.(2)(a) Energas' Position

Energas argues that ELG is the preferable calculation procedure because it is theoretically more precise than ALG. Energas witness Mr. Donald A. Roff asserts that ELG is a straight-line method of determining depreciation rates that takes into account the timing of the expected retirements of assets within a given account. Because ELG takes into account the timing of retirements based on the distribution within the selected survivor curve, it is more theoretically correct than ALG, and provides a better matching between the recording of depreciation and asset consumption.

Energas argues that ALG, on the other hand, assumes that all assets will be retired at the average age, regardless of the actual pattern predicted by the chosen survivor curve. In this way, Energas claims that ALG results in the deferral of depreciation in the early years and does not as closely match reality, as does ELG. Thus, ELG more closely approximates what would happen if the Company depreciated individual assets on an item-by-item basis by recognizing that assets within the group will be retired at different times and in different amounts in a manner that follows the distribution established by the survivor curve selected for that asset group.[247]

In response to concerns that the Company has purchased a high amount of information technology assets in the test year that it is putting in rate base and depreciating, Energas claims that the "law of large numbers" indicates that rates will be stable over time as assets are added by the Company to the base upon which the depreciation rates in this case will be set. Therefore, a balance occurs as assets are continually added, because "additions will exceed retirements almost without exception."[248]

In response to concerns that ELG will require continual rate cases in order to remain accurate, Energas argues that ALG will require continual rate cases as well, because it does not as closely match reality as does ELG and results in the deferral of depreciation in the early years. In any case, Energas argues, there should be no concern that the depreciation rates set in this case will be in place for an excessively long period of time. Energas notes that this is the fourth time its West Texas Division rates have been changed in the last eight years, an average of every two years.[249] Also, the Settlement Agreement, reached between Energas and 59 of the Cities,

[247] Tr. Vol. 9 at pp. 55-59; 81-82.
[248] Tr. Vol. 9 at p. 61, lns. 6-12; p. 64, lns. 9-12.
[249] Tr. Vol. 9 at p. 162, ln. 7 – p. 163, ln. 4.

contains a three-year moratorium.[250] Besides, Energas argues, the Cities can call Energas in for a rate proceeding if they deem such to be necessary as the regulatory authority with jurisdiction over rates within the city limits.[251]

1.a.(2)(b) Cities' Position

The Cities argue that the ELG calculation is very sensitive to the accuracy of the survivor curves, as noted by NARUC.[252] Therefore, the Cities point out that Energas' claim that both ELG and ALG rely on the same life-curve combination is misleading: "while either calculation procedure can rely on a life-curve combination produced in the life analysis, the ELG procedure will produce significantly more erroneous results to the extent the results of the life analysis are not a reliable projection of the future."[253]

The Cities argue that, if the Company fails to file annual depreciation rate studies and corresponding rate cases, customers will always be overcharged based on the known and measurable information in the record from the last rate case. The precision demanded by ELG requires that Energas change the composite rate every year since the dollar weighting of the various declining depreciation rates changes every year. This is inappropriate because Energas' surviving balance for its depreciation study is as of September 30, 1997, and the Company's three highest depreciation rates have already transpired prior to rates going into effect in this proceeding.

The Cities also point out that Energas is requesting ELG-based depreciation rates for the West Texas Distribution System for the first time before this Commission. There is no guarantee that Energas will continually file rate cases to assure proper depreciation rates if Energas obtains favorable rates in this proceeding.

1.a.(2)(c) Examiners' Analysis

The Examiners agree with the Cities that the ELG procedure should not be used in this case. Energas' witness Mr. Roff stated that the nature of the ELG calculation is to "recognize that mix of lives that comprise that average and therefore ELG would have a higher rate in the earlier years."[254] In its attempt to recognize the mix of service lives, ELG theoretically represents "reality," but its errors are magnified over time if the rates are not continually updated. When viewed in light of the limited amount of historical data and detailed information about its assets, Energas has not proven that the use of the ELG procedure is reasonable.

Thus, the Cities are correct that, as Energas' investments in each asset account change over time, the ELG depreciation rate will need to be changed quickly in order to reflect these changes in the early years of the life curve of each group of assets. Put another way, in order for the depreciation rate to be truly as accurate as Energas claims ELG rates are, they must be

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250 Energas' Ex. 15, Attachment B.
251 Energas' Post Hearing Brief at pp. 55-56.
252 Cities' Ex. 88 at p.165.
253 Cities' Initial Brief at p. 53.
254 Tr.Vol. 6 at p. 145.

changed frequently to reflect changes in the asset groups over time. Otherwise, Energas could continue to charge rates based on an outdated depreciation expense which, in this case, could be abnormally high because of significant recent investments in information technology. The Examiners therefore recommend the ALG procedure because the risk of Energas overcharging the ratepayers is much lower.

ALG, in contrast to ELG, uses the average of the entire account, thereby allowing higher depreciation rates later in the average life curve. The ALG procedure, on the other hand, recognizes the difficulty in precisely measuring service lives, and uses broader averages. Though ALG will result in lower rates in the short term, it should produce a more fair and reasonable result if the rates are carried into the future, without the need for continual adjustments to remain accurate.

The Examiners are also unconvinced by Energas' argument that the "law of large numbers" makes the ELG procedure reasonable in this case. Mr. Roff states that additions will more than balance out retirements over time, indicating that Energas should be investing in assets in the future which will more or less match the assets in the accounts at the present time, due to the large amount of assets held by utilities.[255] However, Energas has not proven that this will be the case, for two reasons. First, as the Cities point out, the focus should be on whether <u>current</u> ratepayers would get the benefit of the yearly reductions they are supposed to receive under the ELG procedure.[256] Second, Energas has made significant investments in information technology in the test year, with no guarantee that the same type and amount of investments will be made in the future.

Of particular issue in this case is the high amount of information technology investment during the test year, some of which has relatively short estimated survivor curves that are difficult to accurately estimate because of the scant historical information available. Under ELG, Energas will be able to recover more of this expense sooner, and the rates will be higher than if ALG were used. Therefore, if the Commission allows ELG-calculated rates, the ratepayers are at risk of paying the higher rates into the future if Energas does not continually adjust its rates accordingly.

The Examiners also agree with the Cities' argument that Energas should not use the ELG procedure because it encourages the filing of rate cases. Depreciation is only a part of the overall expenses that Energas may recover in its rates, so filing a rate case to more accurately determine depreciation rates could be piecemeal ratemaking. Even continual ratemaking proceedings would not accurately reflect reality with ELG rates. The ratemaking process is time-consuming, and rates are based on a past test year, so there would be a lag period when the reduction in depreciation rates would not be recognized.

Thus, the Examiners recommend using the ALG procedure because it is the most reasonable in this case. Although Energas claims that ELG is more theoretically correct, the Examiners are convinced that ELG cannot timely reflect current conditions and can result in unfair and unjust rates through time. The ALG procedure recognizes these limitations and

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[255] Tr. Vol. 9 at p. 64.
[256] Cities' Reply Brief at p. 51.

provides a fair average depreciation expense with which to set rates that will continue in effect into the future.

1.a.(3) *Frequency of use of ALG versus ELG*

<u>Contested Issue:</u> Does the frequency of use of either methodology favor ALG or ELG?

<u>Examiners' Recommendation:</u> ALG is the most frequently approved methodology for utility ratemaking purposes and should be adopted for this case.

1.a.(3)(a) Energas' Position

Energas argues that ELG was adopted by this Commission in the TXU Lone Star case, GUD No. 8976. Also, ELG was adopted by the Public Utility Commission and the Nevada Public Service Commission.[257] Also, Mr. Roff testified that ELG is "a generally accepted straight-line method."[258]

1.a.(3)(b) Cities' Position

The Cities point out that the Commission has not approved the use of ELG for any other utility in Texas except for TXU Lone Star Pipeline. The Cities cite two recent Railroad Commission cases where the Commission approved the use of ALG.[259] Also, Mr. Pous testified that Mr. Roff is incorrect when he states that ELG is generally accepted. In fact, Mr. Pous claims, ELG is utilized by a very small minority of energy companies in the United States. In contrast, over 90% of the electric and gas utilities nationwide use the ALG procedure to calculate mass property depreciation rates.[260] Most regulators have rejected ELG in those relatively few instances in which it is being requested. Even the Federal Energy Regulatory Commission (FERC) has specifically denied the use of the ELG procedure.[261]

1.a.(3)(c) Examiners' Analysis

The Examiners agree with the Cities that ELG is rarely utilized by energy companies and their regulators. The record is clear that the only gas utility in Texas that has been allowed to use the ELG procedure is TXU Lone Star, in GUD Nos. 8664 and 8976. However, TXU Lone Star had already switched to the ELG procedure in GUD No. 8664 in 1995, and the Commission approved continued use of ELG in GUD No. 8976, rather than requiring them to switch to ALG. Finally, Mr. Pous' testimony is uncontroverted that energy utilities rarely request the ELG

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[257] Tex. Publ. Util. Comm'n, *ReSouthwestern Electric Power Company,* 7 TEX. PUC BULL. 78, Docket No. 3716 (June 18, 1981) (Energas Ex. 45); Tr. Vol. 6 at p. 149.
[258] Energas' Ex. 18 at p. 10.
[259] Tex. R.R. Comm'n, *Appeal of Southern Union Gas Company from the Action of the Cities of Groves et al.*, Gas Utilities Docket No. 8033, Order, Finding of Fact 38 and Conclusion of Law 27 (February 10, 1992); Tex. R.R. Comm'n., *Appeals of Southern Union Gas Company from the Actions of the City of El Paso,* Gas Utilities Docket NO. 8878, Order, finding of Fact 158 (November 17, 1998). These cases are in the Appendix to the City's Initial Brief at Tabs 1B and 2B, for reference.
[260] Cities' Ex. 98 at p. 39, ln. 11.
[261] *Id*. at pp. 39-40.

procedure, and regulatory authorities deny its use the majority of the time. Therefore, the record is clear that the vast majority of utilities use the ALG procedure, both in Texas and nationwide, and the Examiners' recommended use of ALG is consistent with common utility practice.

1.a.(4) *Straight-line Method of Depreciation*

Contested Issue: Is ELG is a straight-line method of depreciation, in compliance with Commission Rule 7.51(a),[262] or an accelerated method of depreciation?

Examiners' Recommendation: Both ALG and ELG comply with Commission rules; however, the facts of this case favor the use of the ALG methodology.

1.a.(4)(a) Energas' Position

Energas argues that ELG is a straight-line method for calculating depreciation, while ALG could be considered a method of deferred depreciation.[263] Energas first points out that the Commission recently found that ELG is a straight-line method in the TXU Lone Star case.[264] Energas then argues that ELG is straight-line because it slices up the life curves, then takes each of the slices and depreciates that part of the curve in a straight line fashion over the number of years represented by that "slice."[265] Even though this results in a higher depreciation rate in the early years of the curve than does ALG, Energas claims that ELG is closer to the truth, in that it more accurately estimates the actual service lives and retirement ages of the assets.

1.a.(4)(b) Cities' Position

The Cities point out that Energas witness Mr. Don Roff admits that accelerated depreciation results in more depreciation in early years and less depreciation in later years, and that ELG does precisely that.[266] The Cities claim that ELG cannot be a straight-line method because it recovers depreciation over the life of each individual yearlong slice of a survivor curve, rather than basing the depreciation on the average service life of the entire survivor curve.

1.a.(4)(c) Examiners' Analysis

ALG and ELG are both acceptable straight-line methods of calculating depreciation, under Commission Rule 7.51(a). However, in this case, it is more reasonable to use the ALG method because of the inherent problems with ELG as used by Energas in this case. The record is clear that, in this case, ELG results in a greater amount of asset retirements in earlier years than does ALG, though both may be considered straight-line methods.

The Commission has already determined that ELG is an acceptable method of calculating depreciation in the TXU Lone Star case, GUD No. 8664.[267] This year, in GUD No. 8976, the

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[262] 16 TEX. ADMIN. CODE § 7.51(a) (West 2000).
[263] Energas' Post-Hearing Brief at p. 53.
[264] *Id.*
[265] *Id.*
[266] Aligned Cities' Initial Brief at p. 50.
[267] Cities' Ex. 102; Tex. R.R. Comm'n, *Statement of Intent of Lone Star Gas Company and Lone Star Pipeline Company, Divisions of Enserch Corporation, and Ensat Pipeline Company to Increase the IntraCompany City Gate*

Commission again approved the ELG method, for consistency's sake, against the Examiners' recommendation to use ALG. In GUD No. 8664, the Examiner described how both methods are straight-line methods, and the difference in calculations:

> ELG and ALG are both straight-line methods of depreciation; the main difference occurs in how the assets are grouped to determine service lives. The ELG procedure divides the plant investment into individual equal life groups and attempts to recover the depreciation expense for the plant investment on an individual annual life basis for the number of years each group is anticipated to be in service. Thus, the ELG procedure recovers net book cost over the life of each ELG group rather than averaging many components and recovers costs as assets within each retire. ALG, on the other hand, does not divide the plant investment into equal life groups and is designed to recover capital over the total life of the *entire* group. Using ALG, capital recovery occurs when the last unit in the group retires.[268]

This description of ALG and ELG is consistent with Mr. Roff's explanation of the differences between ALG and ELG during his rebuttal testimony.[269] Therefore, the Examiners agree with Energas that, even though it is true that the ELG method results in higher depreciation rates than the ALG method in the early years of the life curves, ELG is still a straight-line method, and could be an acceptable method of calculating depreciation under Commission Rule 7.51(a). Nonetheless, under the facts of this case, the ELG calculation is not preferable to ALG, and the Examiners do not recommend the use of ELG in this case.

1.a.(4)(5) *Examiners' Recommendation on Calculation Procedure*

The Examiners recommend a depreciation calculation using the ALG procedure. The ALG procedure is the most appropriate in this case because (1) Energas has limited historical data and detailed information about the assets underlying the life estimation process, (2) ELG magnifies the error associated with natural inaccuracies between forecasts and actual future events, is time sensitive compared to ALG calculated rates, produces rates that are outdated by the time of implementation, and requires constant rate changes if it is to be applied properly, and (3) ELG is rarely utilized by energy companies and their regulators. These factors lead the Examiners to believe that ELG calculation method could result in depreciation rates that are too high.

The Examiners also recognize that Energas has been using ALG, and do not believe that a change to ELG is warranted. Given Energas' recent investments in information technology, and the difficulty in determining average service lives for such items because of the lack of historical data and detailed information necessary for the accurate estimation of life curves, the

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Rate, Gas Utilities Docket (GUD) Docket No. 8664, Second Order on Rehearing Nunc Pro Tunc, Finding of Fact No. 92.

[268] Tex. R.R. Comm'n, *Statement of Intent to Change the City Gate Rate of TXU Lone Star Pipeline, Formerly Known as Lone Star Pipeline Company Established in GUD No. 8664*, GUD No. 8976, Revised Proposal for Decision, June 16, 2000 at p. 73. (footnotes omitted)

[269] *See generally,* Tr. Vol. 9 at pp. 55-59, 81-82; Examiners' Ex. 2.

record indicates that the ELG method would allow Energas to recover higher depreciation rates for these short-lived assets in the first few years that ELG-based rates are in effect, thus increasing Energas' overall rates. There is no guarantee that Energas would continually adjust its ELG-based depreciation rates to keep them accurate, thus magnifying any errors into the future.

Consequently, the Examiners recommend that the Commission set depreciation rates using the ALG procedure. This is consistent with almost all of the gas utilities in Texas, and most utilities nationwide. Energas has not met its burden of proof to show that a switch to the ELG method is warranted. ALG is more likely to result in a reasonable depreciation expense into the future, and will avoid over-recovery by Energas.

In the alternative, if the Commission disagrees with the Examiners and sets rates using the ELG procedure, the Examiners recommend that the Commission Order Energas to file a rate case with the Commission, for those customers over which the Commission has original jurisdiction, within three years in order to maintain the accuracy of the ELG-based depreciation rates.

1.b. Service Lives and Survivor Curves

The determination of average service lives and survivor curves applicable to each asset group are important since it is the asset's service life and survivor curve that determine the period over which its cost is depreciated. Service lives and survivor curves are equally applicable to and required by both ALG and ELG. Generally, shorter service lives will result in higher depreciation rates and expense than longer service lives. An observed survivor curve is a plot or graph of the recorded retirement and survivor history as a function of age. The observed curve is essentially a graphical representation of history.[270] Iowa curves are standard curves that were empirically developed to describe the life characteristics of most industrial and utility property. They are the result of extensive analysis by professors at Iowa State University.[271] Both parties rely on Iowa curves in developing average service lives in the case.[272]

Energas bases its recommended average service life and survivor curve recommendations on the 1997 Depreciation Study performed for Energas by Mr. Roff of Deloitte & Touche (D&T).[273] The Cities recommend changes to seven (7) asset categories. The parties' positions and Examiners' recommendations are summarized in Table 1.

<u>Contested Issue:</u> What are the appropriate Service Lives and Survivor Curves for Energas' Account Nos. 376, 390.09, 399.86, 399.88, 399.99?

<u>Examiners' Recommendation:</u> The Examiners' recommended Service Lives and Survivor Curves are summarized in the Table 1 below.

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[270] Energas' Ex. 18 at p. 7, lines 18-19.
[271] Cities' Ex. 98, Appendix A.
[272] Cities' Ex. 98 at p. 12; Energas Ex. 18 at p. 8.
[273] Energas' Ex. 18, DSR-1.

Table 1 - Summary of Service Lives and Survivor Curves

Account No.	Description	Division	Energas Life	Energas Curve	Cities Life	Cities Curve	Exam.'s Life	Exam.'s Curve
376	Dist. Plant, Mains		60	R1.5	75	R2	75	R1.5
390.09	Leasehold Improv.		10	SQ	20	SQ	15	SQ
399.86	Gen'l. Plant, PC Hardware	5,10,21	5	SQ	8	R3	8	SQ
399.86	Gen'l. Plant, PC Hardware	2	5	R4	8	R3	8	SQ
399.88	Application Software	5,10,21	8	SQ	15	SQ	10	SQ
399.88	Application Software	2	10	SQ	15	SQ	10	SQ
399.99	OS Software	2	5	R4	15	SQ	10	SQ

1.b.(1) *Account 376, Distribution Plant, Mains*

The Examiners recommend an average service life (ASL) of 75 years and a survivor curve of R1.5.

1.b.(1)(a) Energas' Position

Energas relies on D&T's Depreciation Study and associated workpapers to support its proposal of a 60 year ASL and R1.5 curve for Account 376. In its Depreciation Study, D&T notes: "An analysis of historical retirement activity, suitably tempered by informed judgment as to the future applicability of such activity to surviving property, formed the basis for determination of average service lives and retirement dispersion patterns."[274] The actuarial analysis of historical retirement activity indicates an ASL ranging from 76 to 80 years.[275] The plotted curve was judged by Energas' witness, Mr. Roff, to match an R1.5 Iowa curve.

Mr. Roff supports his departure from his historical analysis for three reasons: (1) a service life of 60 years is a "movement towards this history that we are seeing" (a movement from a current ASL of 55 years); 2) the 60 year ASL is within the range of reasonableness for this type of asset within the industry, and a 75 year ASL is at the very upper end of the range; and 3) the 60 year ASL reflects the expectations of the Company and the impact of their ongoing programs.[276] The most significant ongoing program is Energas' Steel Pipe Replacement

[274] Energas' Ex. 18, DSR-1 at p. 7.
[275] Cities' Ex. 74A.
[276] Energas' Post-Hearing Brief at p. 62.

Program (SPIP). Energas notes that, as of February 1999, it had replaced 106 miles and cathodically protected 681 miles of steel pipe and planned to do one or the other to a remaining 704 miles.[277]

1.b.(1)(b) Cities' Position

The Cities argue that the Company basically ignored the results of its historical life analysis and did not elect to develop or maintain any contemporaneous written documentation of its process to develop its proposal.[278] According to the Cities' witness Mr. Pous, Mr. Roff did not provide any "documentation" or "quantifiable evidence" for his 60 year ASL, given that the historic analysis showed that the ASL to be between 76 and 80 years for Division 5.[279] Further, the Cities argue that neither Mr. Roff nor the Company provides any documentation to support the 60 year ASL for Mains. The notes at the bottom of Mr. Roff's Life Analysis for Account 376-Mains cover sheet begin by stating: "Life analysis indicates increasing life."[280] In spite of the fact that the life analysis shows a 76-80 year ASL, the notes go on to state: "However, Company expects to resume main replacement and CP (cathodic protection) program in the future resulting in more retirements." The notes conclude: "Suggest limiting the increase in ASL to 60 years." The Cities point out that when cross-examined about the Steel Pipe Replacement Program (SPIP), Mr. Roff had little knowledge about the main improvement program:[281]

> Q. Okay. Where it says "However, Company expects main replacement," do you see that?
> A. Uh-uh.
>
> Q. When does the Company expect to resume?
> A. Some point beyond September 30, 1997.
>
> Q. When?
> A I don't have a specific hour, minute and day, no.
>
> Q. Well what century?
> A. I would assume that it has already started. It's already taken place, since this was as of 1997. They have begun to do these things.
>
> Q. To do what?
> A. Enhance their cathodic protection program. I believe there is a specific program that is being addressed. I can't remember, SPIP or SPIC or something like that, some specific name that has taken place for the Company, a main replacement program in West Texas.

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[277] Energas' Ex. 16 at p. 16.
[278] Cities' Ex. 98 at p. 11.
[279] Division 5 is West Texas City Distribution. Division 21 is West Texas Rural Distribution. Division 10 is Energas General Office. Division 2 is Atmos Corporate Office.
[280] Cities' Ex. 74A.
[281] Tr. Vol. 6 at p.63.

Q. When did that program begin?
A. You would have to ask someone else from the Company.

Q. How many mains are they replacing?
A. You would have to ask someone else from the Company.

The Cities support their recommendation of a 75 year ASL and an R2 curve based on Mr. Pous' review of historical data, recognition of longer ASLs attributable to better materials for wrapped mains and coating of mains, and "…the Company's failure to provide any verifiable support for claimed expectations."[282]

1.b.(1)(c) Examiners' Analysis

The Examiners recommend a 75-year ASL and an R1.5 curve, based on the historical actuarial analysis performed by the Company and provided with Mr. Roff's workpapers.[283] Energas' request for an R1.5 curve appears to be reasonable based on the plotted survivor curve used by Mr. Roff. However, Energas' request for a 60 year ASL is not supported by the historical analysis nor is Mr. Roff's justification for departing from the historical actuarial analysis adequately documented. In addition, Mr. Roff showed a lack of knowledge about the Steel Pipe Improvement Program. He could offer only limited background or information about the Company's expectations and was unable to determine who in the Company had provided him with the basis for these expectations.[284] With respect to its proposed ASL for Account 376, Distribution Plant, Mains, the largest rate base account, Energas does not meet its burden of proof.[285] The only documented evidence in the record supports a 75 year ASL and an R1.5 curve.[286]

1.b.(2) *Account 390.09, Leasehold Improvements*

The Examiners recommend an average service life of 15 years and an SQ curve for Account 390.09, Leasehold Improvements. (Use of the SQ curve is not disputed by the parties.)

1.b.(2)(a) Energas' Position

Energas relies on D&T's Depreciation Study for its 10-year proposed average service life for Leasehold Improvements. In its Depreciation Study, D&T notes that 10 years is the "average life of the lease."[287] Energas argues that this is based on the 10-year ASL of the most important lease in question, the lease for the Customer Service Center (CSC).[288] In the alternative, Energas suggests that the ASL be determined based on a weighted average of the various lease terms, rather than the Cities' recommended 20-year ASL.[289]

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[282] Cities' Ex. 98 at p. 12.
[283] Cities' Ex. 74A.
[284] Tr. Vol. 6 at p. 65.
[285] Energas' Ex. 5, WP 6-1.
[286] Cities' Ex. 74A.
[287] Energas' Ex.18, DSR-1 at p. 13.
[288] Energas' Reply Brief at p. 47.
[289] Energas' Reply Brief at p. 48.

1.b.(2)(b) Cities' Position

The Cities argue that the ASL for Leasehold Improvements should be 20 years. They base this recommendation on the initial terms and renewal options of three leases.[290] The record contains 28 leases for which leasehold improvements are included in Account 390.09 with terms ranging from 5 to 20 years.[291] However, information regarding associated square footage or cost of improvements is not in the record.

The Cities note that, during cross-examination, Mr. Roff states that the life of the lease is an appropriate determinant of the ASL for leasehold improvements. Also, Mr. Roff could not recall which leases he looked at to make his ASL determination, nor did he include this information in his workpapers.[292] Later during cross-examination, he recalled that he only reviewed two leases.[293]

1.b.(2)(c) Examiners' Analysis

The Examiners' recommended 15-year ASL for Leasehold Improvements is based on the average of the leases provided in the record. According to Mr. Roff, the life of the CSC lease is a reasonable means by which to determine the ASL for leasehold improvements.[294] However, Energas does not provide information which details or illustrates how the CSC lease is the most important, so the Examiners did not use the CSC lease alone to determine the ASL.

In like manner, the Examiners do not recommend a weighted average. The Company's response to the Cities RFI 4-111 listed the lease date and expiration date of 28 leases included in Account 390.[295] However, Energas did not provide square footage or cost of improvements associated with each lease, so no means exists by which to weight the average. Therefore, the Examiners used a simple average of these lease terms, which yields a 15-year average lease term and ASL.

1.b.(3) *Account 399.86, PC Hardware, Division 2 and Account 399.86, PC Hardware, Divisions 5, 10, and 21*

The Examiners recommend an average service life of 8 years and an SQ curve for Account 399.86, PC Hardware, Divisions 2, 5, 10, and 21.

1.b.(3)(a) Energas' Position

In determining its recommended 5-year ASL for PC Hardware, Energas relies on "data, circumstances, and trends" other than its historical actuarial analysis.[296] This is due to the fact

[290] Cities' Ex. 98, JP-5.
[291] Cities' Ex. 79.
[292] Tr. Vol. 6 at p. 98.
[293] Tr. Vol. 6 at p. 100.
[294] Tr. Vol. 6 at p. 98.
[295] Cities' Ex. 79.
[296] Energas' Brief at p. 58.

that PC Hardware is a fairly new account, created in 1990, and that there was only one asset retirement prior to the 1997 Depreciation Study, making the use of an Iowa retirement dispersion curve suspect. The single retirement in the history of the account occurred when the assets were 3 years old.[297]

Energas notes that D&T worked with Energas personnel in evaluating the types of assets in the account and the expectation for future additions and "recommended a life that is consistent with those technological expectations and the type of assets that are being installed today."[298] Mr. Roff argues that general industry trends indicate that technological advances in PC Hardware will continue.[299] Energas also argues that the 8-year ASL with an R3 curve recommendation by the Cities is inappropriate because, under this curve, 18 percent of the PC Hardware assets in the account would theoretically endure beyond 10 years.[300]

1.b.(3)(b) Cities' Position

The Cities argue that the only evidence provided by the Company is D&T's historical actuarial analysis, which indicates an 8-year ASL and an R3 survivor curve, and that Mr. Roff has not provided documentation to depart from the historical analysis.[301] The Cities' witness, Mr. Pous, based his recommendation on D&T's historical analysis, the type of investment normally in this account, and his judgment.[302]

Mr. Pous' 8-year ASL recommendation is based on D&T's historical analysis, which indicates a 12-year ASL and includes a 1990-1997 band analysis survivor report, which concludes with a realized life of 7.85 years.[303] The source of Mr. Pous' R3 curve recommendation is D&T's 1997 Depreciation Study.[304]

The Cities argue that Energas has not met its burden of proof in departing from its historical analysis to determine the ASL and curve for PC Hardware because it failed to provide quantifiable, documented evidence for the change.[305] Under cross-examination, Mr. Roff appeared to have little direct knowledge regarding the PC Hardware account:

> Q. Do you have a break-out as to how much of the plant account for PC hardware is made up by CPUs?
> A. I don't have that break-out, no.
>
> Q. Or how much is monitors?
> A. I do not have that break-out.

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[297] *Id.*
[298] Tr. Vol. 6 at pp. 118 and 155.
[299] Energas' Ex. 19 at p. 20.
[300] *Id.*
[301] Cities' Initial Brief at p. 66.
[302] Cities' Ex. 98 at p. 16.
[303] Cities' Ex. 80A. Realized Life is the average years of service experienced to date from the assets originally in the account.
[304] Energas' Ex. 18 at p. 14. Cities' Ex. 80A.
[305] Cities' Initial Brief at p. 67.

Q. I was just establishing you don't have it for any of those particular items that are in PC hardware, do you?
A. That is correct.[306]

Also, the Cities point out that Mr. Roff was not sure whether printers were in the account or not.[307] Mr. Roff also contended that the different types of PC Hardware would all have the same service lives, but later he amended the statement to indicate that the statement only applied to laptop-type computers and they were only a small percentage of the computers. Rather, most of the computers are "desk units."[308]

Also, the Cities note that there are brief notes on D&T's cover page for the life analysis for PC Hardware that indicate that they used an "ASL selection based on technology and Company expectations."[309] Yet there was no documentary support for this statement. In response to a question from D&T to the Company, an unidentifiable person responded via e-mail by saying that "I would expect a 3-5 year replacement for most PCs."[310] Mr. Roff did not know who wrote that note, nor did D&T or the Company document the source of this recommendation. Therefore, there is no indication whether the statement only applied to CPUs. Also, there is no indication with regard to what percentage of the account is made up of what types of hardware. The Cities argue that the unsubstantiated statement by an unknown person should be given no weight.[311]

1.b.(3)(c) Examiners' Analysis

The Examiners' recommendation of an 8-year ASL and an SQ curve is based on Energas' failure to adequately document the source of its recommended departure from D&T's historical analysis. Given the limited value of Energas' historical analysis with only one retirement in this account, the Examiners find that Energas failed to meet its burden of proof on this issue because it failed to document and present the sources of its recommendation in the record.

The Examiners' 8-year ASL recommendation is based upon the only documented evidence in the record, the realized life result of the historical actuarial analysis.[312] The Examiners recommend an SQ curve, based upon Mr. Roff's admission that no curve can be determined using the historical actuarial analysis with only one retirement and, thus, only one point by which to fit a curve.[313] In such an instance, the curve possibilities are infinite. An SQ curve reflects the Company's current curve for this account for Divisions 5, 10, and 21.

[306] Tr. Vol. 6 at p. 91.
[307] Tr. Vol. 6 at p. 90.
[308] Tr. Vol. 6 at p. 91.
[309] Cities' Ex. 80.
[310] Cities' Ex. 76 at p. 5.
[311] Cities' Brief at p. 68.
[312] Cities' Ex. 80A.
[313] Tr. Vol. 6 at p. 121.

1.b.(4) *Account 399.88, Application Software, Divisions 2, 5, 10, and 21, and Account 399.99, Operating System (OS) Software, Division 2*

The Examiners recommend an average service life of 10 years and an SQ curve for Account 399.88, Application Software, Divisions 2, 5, 10, and 21, and Account 399.99, Operating System (OS) Software, Division 2.

1.b.(4) (a) Energas' Position

As shown in Table 1, Energas recommends: an ASL of 8 years and an SQ curve for Account 399.88, Application Software, Divisions 5, 10, and 21; an ASL of 10 years and an SQ curve for Account 399.88, Application Software, Division 2; and an ASL of 5 years and an R4 curve for Account 399.99, Operating System (OS) Software, Division 2.[314]

The support in the record for these recommendations consists of the direct and rebuttal testimony of Energas' depreciation witness, Mr. Roff. In his direct testimony, Mr. Roff recommends a 5-year ASL and an R4 curve for Account 399.88, Application Software, as opposed to Energas' recommendation of a 10-year ASL and an SQ curve. Mr. Roff's recommendation is derived from D&T's 1997 Depreciation Study and differs from the Company's recommendation for this account in this case.[315]

1.b.(4)(b) Cities' Position

The Cities argue that the Company has failed to support its life proposals for these software accounts. As shown in Table 1, the Cities recommend: an ASL of 15 years and an SQ curve for Account 399.88, Application Software, Divisions 5, 10, and 21; an ASL of 15 years and an SQ curve for Account 399.88, Application Software, Division 2; and an ASL of 15 years and an R4 curve for Account 399.99, Operating System (OS) Software, Division 2.

The Cities' recommendation is based on several considerations. First, the Cities point to an Energas Board of Directors meeting where the Board was told that the new software system "will meet the Company's needs for the next 10-15 years."[316] Second, the Company chose the Oracle software package as one major component of its investment (included in Account 399.88, Division 2). The Oracle software system provides both scalability and reliability, which, according to Mr. Pous, translates into extended useful life.[317] Third, the prior legacy software system is still providing service for limited purposes.[318] This means that the investment in the Legacy system is providing and has provided service for time frames equal to or greater than the life proposed by Mr. Roff for the new software.[319] Fourth, senior Atmos officers have stated that

[314] Since updated information regarding the ASL's and curves for these accounts was not included in Mr. Roff's direct testimony (Energas Ex. 18), the Company's position was determined from Mr. Pous' direct testimony (Cities Ex. 98 at p. 12) and Energas' Brief at pp. 59-60.
[315] Energas' Ex. 18, DSR-1 at p. 17; Energas' Brief at pp. 59-60.
[316] Cities' Ex. 98, Exhibit JP-6.
[317] Cities' Initial Brief at p. 69.
[318] Energas' Ex. 19 at p. 21.
[319] Cities' Ex. 98, JP-6.

the new software investments were designed to help facilitate the acquisition of local distribution companies.[320] The Cities argue that it is unfair to charge high levels of depreciation to current customers, when, in part, the software was installed for the benefit of future customers.[321]

1.b.(4)(c) Examiners' Analysis

The Examiners' recommend an ASL of 10 years and an SQ curve for all of the above accounts: an ASL of 10 years and an SQ curve for Account 399.88, Application Software, Divisions 5, 10, and 21; an ASL of 10 years and an SQ curve for Account 399.88, Application Software, Division 2; and an ASL of 10 years and an SQ curve for Account 399.99, Operating System (OS) Software, Division 2.

The Examiners' ASL recommendation is based on the lower end of the range documented in the summary of a Special Meeting of Board of Directors: "Mr. Goodman stated that the Company, in evaluating the CIS alternatives, retained the consulting services of Micon, Inc. to aid the Company in choosing a system that will meet the Company's needs for the next 10-15 years."[322] While this statement is far from a firm basis by which to determine an average service life, it is, quite frankly, about the only number in the record that provides any support whatsoever to an average service life for these software accounts.

The Company fails to adequately support its recommendations or meet its burden of proof in its direct and rebuttal testimony for Account 399.88, Application Software. Mr. Roff's recommendations appear to be based on "the influence of technology changes."[323] However, the historical actuarial analysis upon which the recommendations may have been based was not made part of the record. Thus, the foundation of the Company's recommendations for Account 399.88 is very weak.

Mr. Roff's direct testimony also does not include a basis for the Company's recommendation for Account 399.99, Operating System (OS) Software, Division 2; this account does not appear to have been included in the 1997 Depreciation Study, and no specific testimony is provided to support the recommendations for this account.

Mr. Roff's rebuttal testimony with respect to the software accounts at issue in the case consists of the following:

> Mr. Pous references a Board of Directors presentation, which addressed in general terms the Company's technology needs for the next 10-15 years. This by no means equates to the appropriate life of these asset categories for depreciation purposes. While past legacy systems may have lasted upwards of fifteen years, software advancements will continue to occur, making that period excessive for

[320] Cities' Ex. 7 at p. 2.
[321] Cities' Initial Brief at p. 70.
[322] Cities' Ex. 98 at JP-6.
[323] Energas' Ex.18, DSR-1 at pp. 18-19.

> depreciation purposes. My recommendation is based upon a *more rigorous evaluation* and should be adopted.[324]

The Examiners are unable to find in the record any evidence of Mr. Roff's "more rigorous evaluation." In its Post-Hearing Brief and Reply Brief, Energas refers often to technological change as a basis for its ASL recommendations. However, the Company does not offer evidence in the case documenting the effect this technological change would have on the average service lives and survivor curves of the disputed software accounts.[325] Therefore, the Examiners reject Mr. Roff's five-year recommendation and use a 10-year ASL for these accounts, based on the information in the record that the Company may expect 10-15 years of service from these assets. The Examiners used the lower end of this range to reflect a conservative estimate, to reflect the Company's claims that this ASL should be shorter because of continuing changes in technology.

Finally, the Examiners' SQ curve recommendation is based on the Company's current and recommended use of this curve for Account 399.88 and the absence of support in the record for any other type of curve for these accounts.

1.c. Net Salvage Factors

Net salvage factors have a significant impact on the depreciation rates selected for groups of assets. A greater net salvage factor results in a lower depreciation rate. A lesser net salvage factor results in a higher depreciation rate.

1.c.(1) *Third Party Reimbursements*

Third party reimbursements occur in situations where plant is retired due to an act of an entity outside the utility, such as a contractor who cuts a gas line while digging a trench. If the third party reimburses the utility for replacement of the retired investment, the utility must account for the reimbursement.

<u>Contested Issue:</u> Should third party reimbursements be included in the net salvage calculation?

<u>Examiners' Recommendation:</u> No. The Examiners recommend that the third party reimbursements disputed in this case be excluded from the calculation of net salvage and accounted for in accordance with the National Association of Regulatory Utility Commissioners (NARUC) Interpretation 67.

1.c.(1)(a) Energas' Position

Energas has requested that reimbursements that are applicable to the cost of replacement be excluded from the calculation of net salvage and credited to associated plant accounts. Energas maintains that this has been its practice since 1995, prior to which, it included

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324 Energas' Ex. 19 at p. 21. (emphasis added)

325 Energas' Post-Hearing Brief at pp. 59-61. Energas' Reply Brief at pp. 50-51.

replacement reimbursements in the calculation of net salvage.[326] Excluding reimbursements from the calculation of net salvage lowers the salvage value, thus increasing the depreciation rate. If these reimbursements are credited to plant accounts, two things happen: (1) the overall rate base decreases, thus decreasing the return on rate base; and (2) the balance in the plant account is lower, thus decreasing depreciation expense. Energas' witness, Mr. Roff, relies on NARUC Interpretation 67 as support for Energas' treatment of third party reimbursements:

> The cost of plant retirements shall be accounted for in accordance with the rules applicable thereto. The cost of new plant should be included in the appropriate plant accounts at actual cost of construction. The reimbursement received shall be accounted for (a) by crediting operation and maintenance expenses to the extent of actual expenses occasioned by the plant changes and (b) crediting the remainder to the reserve for depreciation, unless contractual terms definitely characterize residual or specific amounts as applicable to the cost of replacement. In the latter event, appropriate credits should be entered in the plant accounts.[327]

1.c.(1)(b) Cities' Position

The Cities argue that the third party reimbursements should be included in the calculation of net salvage. Including reimbursements in the calculation of net salvage increases the salvage value, thus decreasing the depreciation rate.

The Cities cite the same NARUC Interpretation 67 as support for its argument to include third party reimbursement in the calculation of net salvage. On page 69 of the Cities' Reply Brief, NARUC Interpretation 67 is provided as shown above with the exception of the last sentence, which is excluded. This last sentence appears to support Energas' position. The Cities focus instead on the second to last sentence of Interpretation 67, which allows reimbursements to be credited to plant accounts only if contractual terms definitely characterize residual or specific amounts as applicable to the cost of replacement. The Cities argue that Energas did not provide evidence of these contractual terms. In addition, the Cities take issue with Energas' accounting treatment of the third party reimbursements when the Company credits these amounts to plant accounts.

Finally, the Cities take issue with Energas' mathematical calculations of net salvage value for Account 376, Distribution Mains, as shown in Cities Exhibit 84. On page 67 of its Reply Brief, the Cities note that the net salvage value, including third party reimbursements, is negative 1.5 percent rather than negative 24 percent, as shown on Cities Exhibit 84.

1.c.(1)(c) Examiners' Analysis

The Examiners agree with Energas that it has properly excluded the disputed third party reimbursements from the calculation of net salvage and accounted for them in accordance with the National Association of Regulatory Utility Commissioners (NARUC) Interpretation 67.

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[326] Energas' Post-Hearing Brief at p. 64.
[327] Energas' 19 at p. 23, lines 11-18. (emphasis added)

The proper treatment of third party reimbursements hinges on whether these reimbursements are for replacement of the retired asset or are the amount received for the actual property retired. Under the definitions of "Replacing or replacement" and "Salvage Value" in the Uniform System of Accounts (USOA)[328], the Examiners view the contested third party reimbursements, in this case, to be amounts received for the construction or installation of utility plant in place of plant retired, not the salvage amounts received for property retired. The net salvage factor worksheet for Account 376, which is part of D&T's 1997 Depreciation Study, clearly associates reimbursements with additions and salvage with retirements.[329] Therefore, the Examiners conclude that Energas has properly excluded third party reimbursements from net salvage and properly credits these amounts to plant accounts, in accordance with NARUC Interpretation 67.

Energas is correct that the Cities' arguments are an attempt to include third party reimbursements in net salvage. The Cities claim that Energas made a mathematical error on its net salvage factor worksheet for Account 376, and that net salvage should be negative 1.5 percent, not negative 24 percent, as shown on the worksheet.[330] Nonetheless, Energas is correct that the Cities are merely including third party reimbursements in net salvage when it claims the mathematical error. Energas explained that reimbursements are listed on the net salvage factor worksheet because D&T took into account the fact that, prior to 1995, Energas booked reimbursements to the accumulated depreciation account, rather than directly lowering the plant addition amounts upon which depreciation would be taken. The calculation on the worksheet was only for the purpose of accounting for the change in plant levels due to the reimbursements booked to the accumulated depreciation account prior to 1995, as explained by Mr. Roff.[331] When the correct components of net salvage are used (salvage, cost of removal, and retirements), they yield an average of negative 25% for net salvage over the years covered. Thus, the Examiners conclude that the Cities' recommendation should be rejected because it is an attempt to include reimbursements in salvage, in light of the Examiners' recommendation to exclude third party reimbursements from the calculation of net salvage factors.

The Cities do not contest whether Energas properly accounts for third party reimbursements that are "applicable to the cost of replacement," when the Company credits these amounts to plant accounts as opposed to crediting them to the reserve for depreciation. However, as long as these reimbursements are treated in a manner which reduces the rate base, their effect should be consistent with NARUC Interpretation 67 and accurately reflected in the overall revenue requirement and rates.

[328] 18 CFR Part 201, pp. 523-524 (April 1, 2000); Cities' Initial Brief at p. 73.
[329] Cities' Ex. 84. The reimbursement ratio of 1% equals the reimbursement amount of $1.12 million divided by the additions amount of $84.34 million. The salvage ratio of 28% equals the salvage amount of $1.89 million divided by the retirement of $6.63 million.
[330] Cities' Ex. 84.
[331] Tr. Vol. 6 at 133; Energas' Reply Brief at p. 52.

1.c.(2) *Net Salvage Factors for Account 376, Distribution Mains, and Account 378, All Other Distribution Plant*

Contested Issue: **What is the appropriate net salvage factor for Accounts 376, Distribution Mains, and Account 378, All Other Distribution Plant?**

Examiners' Recommendation: The Examiners recommend a net salvage factor of negative 15 percent for both Account 376, Distribution Mains, and Account 378, All Other Distribution Plant.

1.c.(2)(a) Energas' Position

Energas proposes a net salvage factor of negative 15 percent for Account 376, Distribution Mains, and a net salvage factor of negative 25 percent for Account 378, All Other Distribution Plant.[332] The net salvage factors for these two accounts are the only ones disputed by the Cities. Energas bases its net salvage factor recommendations on the 1997 Depreciation Study performed for Energas by Mr. Roff of Deloitte & Touche (D&T).[333] According to Energas' Brief, the net salvage factors were selected by D&T "…based on historical experience, recent trends, and anticipated future events."[334] D&T's net salvage worksheets for account 376 for Divisions 5 and 21 are summarized in Table 2.[335]

Table 2 - Summary of Net Salvage Worksheets - Acct. 376

	A	B	C	D	E
Division	Additions	Retirements	Reimbursements	Salvage	Removal
5	5,130	6,632	1,123	1,890	3,543
21	84,344	1,340	8	641	239
Total	89,474	7,972	1,131	2,531	3,782

Net Salvage Factor = $\frac{\textbf{Salvage (D) less Cost of Removal (E)}}{\textbf{Retirements (B)}}$ **= (15.7%)**
(excluding reimbursements)

Note: amounts in thousands

The net salvage worksheets in the record for Account 376 include a summary sheet and a statistical compilation of historical experience for each of Divisions 5 and 21. As shown in Table 2, historical experience indicates a net salvage factor of negative 15.7% for Account 376, Distribution Mains. D&T selected negative 15 percent as a net salvage factor for Account 376, Distribution Mains.

[332] Energas refers to this account as both Account 37X and Account 378; Cities refer to it as Account 378.
[333] Energas' Ex. 18 at p. 13.
[334] Energas' Initial Brief at p. 63.
[335] Cities' Ex. 98, JP-8 at pp. 1-4.

The historical experience for Account 378, All Other Distribution Plant, does not appear in the record. Nor does documentation of recent trends and anticipated future events for Account 378 appear in the record.

1.c.(2)(b) Cities' Position

The Cities argue that Energas' proposed net salvage factors for both Account 376 and Account 378 should be negative 5 percent. Cities' witness, Mr. Pous, derived the negative 5 percent factor by including reimbursements in the net salvage value calculation.[336] Using the values in Table 2, this calculation results in negative 1.5 percent, as shown in Table 3.

Table 3 - Calculation of Net Salvage Factor Including Reimbursements

$$\textbf{Net Salvage Factor} = \frac{\textbf{Salvage (D) less Cost of Removal (E) plus Reimbursements (C)}}{\textbf{Retirements (B)}}$$

(including reimbursements)

Net Salvage Factor = (1.5%)

Note: based on historical experience data for Account 376 (Table 1)

The Cities also point out in their Reply Brief that, with respect to the determination of net salvage factors, Energas has done a poor job of documenting the consideration and impact of recent trends and anticipated future events:

> As noted several times previously, the Company does not have one word associated with its input for net salvage of distribution plant in this proceeding. Even if one were to stretch his imagination and claim that by simply stating it will continue its steel pipe replacement program and cathodic protection program amounts to the Company's input, this in no way establishes any basis for the excessive negative net salvage proposal.[337]

Also, the Cities provide support for its increased net salvage levels of negative 5 percent by pointing out that the Company will experience economies of scale with respect to cost of removal as the Company experiences a greater level of retirements than experienced in the past. The Cities do not quantify the savings anticipated from these economies of scale.

1.c.(2)(c) Examiners' Analysis

The Examiners' recommendation of Net Salvage Factors of negative 15 percent for both Account 376 and Account 378 is based on the historical experience for Account 376 that is in the record.[338]

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[336] Cities' Ex. 98 at p. 29.
[337] Cities' Reply Brief at p. 71.
[338] Cities' Ex. 98, JP-8 at pp. 1-4.

Energas presented insufficient evidence to justify its requested negative 25 percent net salvage factor for Account 378. The only documentation found in the record for Energas' recommended negative 25 percent is D&T's Salvage and Cost of Removal Analysis summary sheet for Account 378, Distribution Plant, Division 5, which is included without statistical backup as the last page of Cities Exhibit 87A. This summary sheet simply includes D&T's selection of negative 25 percent along with the following notes:

> COR expected to exceed Salvage. See total distribution plant analysis. Bulk of COR is for Mains and/or Services. Recent history reflects change in accounting for meter. Limit Salvage to 5%. Limit COR to 30%.[339]

The above is the extent of Energas' justification for its selection of a negative 25 percent salvage value for Account 37X. It appears that the selection relies on the "total distribution plant analysis." If this is a separate analysis, it was not clearly identified as part of the record. If this is the historical analysis for Account 376, which was summarized in Table 2 above, then the appropriate net salvage factor is negative 15 percent, as recommended by the Examiners. Otherwise, Energas' request for negative 25 percent lacks any documented justification.

With respect to the effect of economies of scale on cost of removal in the future, the Cities fail to quantify the effect this will have on net salvage. To the extent that these savings are not reflected in the historical activity, the Examiners do not consider these savings to be known and measurable.

1.d. Fully Depreciated Accounts

<u>**Contested Issue:**</u> **Has Energas properly treated fully depreciated accounts?**

<u>**Examiners' Recommendation:**</u> **Yes. The Examiners recommend that the Commission reject the Cities' proposal regarding fully depreciated accounts to decrease Energas' requested depreciation expense by $772,844 and decrease rate base by $2,318,533.**

1.d.(1) *Energas' Position*

Energas does not deny that assets in several accounts became fully depreciated prior to this rate case. Nor does Energas contest that this was the case for the twenty-one accounts listed in Schedule JP-ll, the spreadsheet presented by the Cities' witness, Mr. Pous, to illustrate his determination of over-collection of rates related to these accounts.[340] Energas asserts that it properly accounted for fully depreciated accounts and that no related adjustments to depreciation expense are necessary. Energas asserts that it was following Generally Accepted Accounting Principles (GAAP) when it ceased booking depreciation when the accumulated depreciation was equal to its investment balance in these accounts. In addition, Energas asserts than any type of adjustment or refund associated with these accounts amounts to retroactive ratemaking. The Company argues further that it utilized previously authorized depreciation rates, and that rates

[339] Cities' Ex. 87A, last page. "COR" is Cost Of Removal.
[340] Cities' Ex. 98, JP-11.

are set on a prospective basis, based on the test year presented by the utility, as adjusted for known and measurable changes.[341]

1.d.(2) *Cities' Position*

The Cities argue that Energas has over-charged its ratepayers and violated the Texas Utilities Code by eliminating the booking of depreciation expense of fully depreciated accounts, while at the same time continuing to collect from ratepayers those corresponding depreciation expenses. Mr. Pous notes that Energas is required to keep its books and records "accurately and faithfully in the manner and form prescribed by the Railroad Commission," according to Section 102.101 of the Texas Utilities Code. Also, the depreciation account is to be kept in accordance with the rates and methods prescribed by the Commission.[342] Mr. Pous notes that utilities are required to carry a proper and adequate depreciation account in accordance with the rates prescribed by the Railroad Commission under Section 104.054 of the Texas Utilities Code.[343] Mr. Pous argues that a utility must obtain regulatory approval before it is allowed to change depreciation rates, and that Energas unilaterally changed its depreciation rate to zero for the fully depreciated accounts without Commission approval.[344]

The Cities estimate over-accruals of $2,318,533 and recommend a reduction to rate base of this amount and a reduction of depreciation expense of $772,844.[345]

1.d.(3) *Examiners' Analysis*

The Cities do not dispute that Energas has recorded depreciation expense utilizing its previously authorized depreciation rates until an asset is fully depreciated. Therefore, Energas effectively rebuts the Cities' argument that Energas has violated the Texas Utilities Code by setting the depreciation rate to zero for fully depreciated accounts when it argues that Energas did not change its rates: "Once an account has become fully accrued, it defies common sense to continue to accrue depreciation for that account. Fully accrued means what it says. This does not constitute changing rates."[346]

Applying over-accrued depreciation as a reduction to the rate base, as the Cities propose to do, also does not make sense. Once an account is fully depreciated, no further depreciation should be applied to that account. Energas is correct that it correctly utilized previously-approved depreciation rates and GAAP when it ceased booking depreciation, and any type of refund or adjustment would amount to retroactive ratemaking.

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[341] Energas' Reply Brief at p. 56.
[342] TEX. UTIL. CODE ANN. § 102.152 (Vernon 1998).
[343] Cities' Initial Brief at p. 79.
[344] *Id.*
[345] Cities' Ex. 98, JP-ll. Cities' Initial Brief at p. 81.
[346] Energas' Post-Hearing Brief at p. 66.

2. OTHER[347] POST-EMPLOYMENT BENEFITS (OPEBS): SFAS-106

The Examiners' recommend a pension and OPEB expense of $882,188. In doing so, the only adjustment the Examiners make to Energas' requested SFAS-106 expense is an $86,000 negative adjustment for the use of an updated discount rate.

In 1993, Energas switched from a cash, or "pay-as-you-go" system of accounting to the Statement of Financial Accounting Standard 106 (SFAS-106) accrual approach for OPEBs.[348] The accrual approach to accounting for OPEBs was adopted by the Financial Accounting Standards Board in SFAS-106 in December 1990, altering the way in which companies accounted for OPEBs for fiscal years beginning in 1992. Before SFAS-106, firms accounted for these benefits on a "pay as you go" or cash basis, recognizing them when the costs were paid rather than when the firm received the services for which the benefits were compensated. SFAS-106 adopts an accrual method, requiring recognition of OPEB costs as they are earned by current employees.[349] It was determined that an actuarially-derived level may be more appropriate for financial reporting purposes because the actual current level of expense may not be representative of normalized long term costs for such items.[350]

The Company's proposed expense requirement for SFAS-106 is $968,188.[351] The Cities recommend that the Company's SFAS-106 expense be reduced to a negative $550,474. The Cities allege that five adjustments are required to the SFAS-106 expense. The first is due to a change in the number of employees. The second is a reduction in the medical cost trend. The third relates to the discount rate used to calculate the SFAS-106 expense. The fourth is an adjustment for over-recovery of the transition obligation that has been amortized since 1993. The fifth is an adjustment to recognize that ratepayers have lost benefits due to the Applicant's alleged failure to establish an external fund. The Cities claim that these adjustments warrant a reduction of the Company's SFAS-106 expense to a negative $550,474.[352]

2.a. Change in Number of Employees

<u>Contested Issue</u>: Should the Cities' adjustment for a reduction in the number of employees be adopted?

<u>Examiners' Recommendation</u>: No. The Examiners recommend no adjustment for changes in the number of employees.

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[347] The "other" is intended to exclude pension benefits; what is left generally consists of retirees' life insurance and medical and dental care benefits. *Southwestern Bell Telephone Co. v. FCC*, 28 F.3rd 165 (D.C. Cir. 1994).
[348] Cities' Ex. 98 at p. 61.
[349] *Southwestern Bell Telephone Co. v. FCC*, 28 F.3rd 165 (D.C. Cir. 1994).
[350] *Id*.
[351] Energas' Post-Hearing Brief at p. 81.
[352] Cities' Initial Brief at p. 81; Cities Reply Brief at p. 79.

2.a.(1) *Energas' Position*

Energas argues that the Cities' $98,941 downward adjustment should be rejected because Mr. Pous includes all employees in his calculations, whereas Ms. McDaniel, Energas' rebuttal witness, includes only employees aged 45 or older in her valuation. This age parameter is necessary because employees must earn 10 years of service prior to reaching eligibility for benefits, and when it is applied, it turns out that there is a net increase of only one employee between the 1998 evaluation and the 1999 evaluation, and this change does not warrant any adjustment.[353]

2.a.(2) *Cities' Position*

The Cities argue that current employee levels for Energas and Atmos have decreased since the October 1, 1998 employment data relied on by Energas' witness Ms. McDaniel. Therefore, Mr. Pous reduced SFAS-106 cost on an average cost per employee basis, and further reduced the average cost per employee for the expense capitalization ratio and the applicable allocation factors, to produce an expense level for the Energas West Texas Distribution System. This adjustment reduced SFAS-106 expense by $98,941.[354]

The Cities also claim that Energas failed to determine the age of the employees leaving and joining the Company, so Ms. McDaniel's net change in employees is meaningless in determining the impact of a decline in the number of employees on overall cost.[355]

Finally, the Cities claim that there have been further and significant decreases in employee levels since September 1999, as testified to by Mr. Lawton, whereas Ms. McDaniels only compares employee levels between October 1998 and October 1999.[356]

2.a.(3) *Examiners' Analysis*

The Examiners recommend that Energas' proposal not be adjusted for changes in the number of employees. Ms. McDaniel's rebuttal testimony is clear that Mr. Pous' recommendations should be rejected because he uses the total number of employees, rather than those eligible for retirement benefits. The Cities fail to explain why Mr. Pous' adjustment is accurate, or otherwise address Ms. McDaniel's rebuttal testimony, and the Examiners consequently find no merit in the Cities' argument.

The Examiners further reject the Cities' argument that Ms. McDaniel's net change in employees is meaningless because she failed to determine the age of the employees leaving and joining the Company. The Cities did not establish the relevance of this information, nor the effect it should have on SFAS-106. During cross examination, Ms. McDaniel testified that the per capita claim costs for the fiscal year 2000 valuation showed the average cost for those

[353] Energas' Ex. 20 at pp. 5-6.
[354] Cities' Ex. 98 at p. 57; Schedule JP-13.
[355] Cities' Reply Brief at p. 75.
[356] Tr. Vol. 7 at p. 115.

employees over 65 was three times higher than those under 65, and she identified the numbers of employees in both age categories.[357] However, she also testified that “We do not break down that cost to that level.”[358] The Cities did not establish that Ms. McDaniel either should have, or did, take this into account in her analysis, and there is no indication that it would change her recommendation if she did take it into account.

Likewise, Mr. Pous did not indicate whether he took such information into account in his analysis or address how many employees fall within which category in his testimony. This leads the Examiners to believe that, if this information made any difference at all, Mr. Pous’ suggested changes could be subject to the same problem. Therefore, the Examiners conclude that Mr. Pous’ suggested adjustment should not be adopted because it is not a known and measurable change, and Ms. McDaniel’s testimony on this subject effectively rebuts Mr. Pous’ testimony.

2.b. Health Care Cost Trend

<u>Contested Issue</u>: Should the Cities’ reduction of OPEB expenses by $273,513 for Health Care Cost Trends be adopted?

<u>Examiners’ Recommendation</u>: No. The Examiners recommend approval Energas’ expenses for Health Care Cost Trends without adjustment.

2.b.(1) *Energas’ Position*

Ms. Margaret McDaniel of Towers Perrin testified on behalf of Energas that “as the actuary, I believe the assumed health care cost trend is appropriate and, based on continued upward trends in health care costs, increased the assumption in fiscal year 1999.”[359] She further testified that the assumed health care trend includes many factors—health care inflation, changes in health care utilization or delivery patterns, technological/medical advances, and cost shifting (private sector and governmental). The trend excludes plan changes, demographic changes (retirees and dependents), and plan selection. While managed health care organizations (HMOs) did help hold down health care costs in the mid to late ‘90s, trends are on the rise again.[360]

Ms. McDaniel further estimated health care trends into the future. Health care cost increases are assumed to hit double digits in 2000 for retirees under 65 and a very high 24% for retirees over age 65. Among the factors which contribute to this are: strong demand for medical services and products; rising prescription drug costs; market pressures on HMOs to increase returns; increased use of expensive technology and diagnostic tests; and industry consolidation.[361] This health care cost trend is also confirmed for reasonableness by a survey of

[357] Tr. Vol. 8 at pp. 125-127. This information is in Examiners Ex. 1, p. MS-2.
[358] Tr. Vol. 8 at p. 125.
[359] Energas Ex. 20 at p. 6.
[360] *Id.*
[361] *Id.*

the Fortune Electric and Gas Utility Companies and an informal Towers Perrin survey that shows that companies are increasing their ultimate trend assumption for fiscal 2000 reporting.[362]

Energas argues that Mr. Pous' recommendation should be rejected because he fails to include $2,302,000 of Energas' costs in his calculation.[363] Instead, Mr. Pous only looked at shared services cost and did not review or include Energas' costs.[364] Ms. McDaniel, on the other hand, testified that the year 2000 costs for the Company showed a 17 percent increase in costs.[365] Therefore, Energas argues that Ms. McDaniel's cost trends are reasonable and are supported by the most recent trends in the industry and for Energas itself.

In response to Mr. Pous' argument that Energas has experienced a 1.2% negative health care cost between 1993 and 1999, Energas argues that that number is misleading and does not reflect the health care trends for the Company's retirees. Instead, Energas argues that it is the 1999 average health care cost per employee compared with 1993, and includes items that are not part of the retiree health care trend, such as: a blended group of active employees and retirees; any plan changes since 1993; demographic changes; number of covered dependents; and plan selection.[366]

Energas also argues that the Health Care Finance Administration (HCFA) data relied on by Mr. Pous is not trustworthy and is inappropriate for comparison with Atmos and Energas, as testified to by Ms. McDaniel.[367] She states that the HCFA data are based on national experience for *all ages* and only include the medical CPI component of the trend. She does not use them because, in her own words, "I have a number of other sources that I believe to be more reliable."[368] Also, they are not appropriate for use with Atmos or Energas because there is a difference in the design of the programs that Atmos has which "may drive people to use—utilize coverage differently than what HCFA is pulling together from a total standpoint. Also the demographics, the age of the group, the geographic location of where they live, the subsidies that are provided by the employer, the coordination methodology with Medicare."[369]

Finally, Energas points out that Ms. McDaniel is an actuary who has been retained by Atmos, so she should know the Company's health cost trends, which were in fact up 17% for the year 2000 over the prior year.[370]

2.b.(2) Cities' Position

The Cities argue that Energas' estimates of health care cost trends initially used to calculate SFAS-106 costs in 1993 have proved to be significantly overstated. The Company's actual experience has been a 1.2% decrease in health care cost per employee since 1993. The

[362] *Id.*
[363] Tr. Vol. 8 at pp. 160-161.
[364] Energas' Post-Hearing Brief at p. 70.
[365] Tr. Vol. 8 at p. 162.
[366] Energas' Reply Brief at p. 59.
[367] Tr. Vol. 8 at pp. 137, ln. 25 – p. 139, ln. 14.
[368] *Id.*
[369] *Id.* at p. 139, lns. 7-14.
[370] *Id.* at p. 162, lns. 21-25.

Company's previous estimates have also proven to be greater then the annual percent change in medical prices for the past five years, as published by the HCFA.[371]

Further, the Cities argue that the Company's own actuarial analysis states that the aggregate of the interest and service cost components of the study would decrease 11.3% for each 1% reduction in assumed health care cost trend rates. They argue that, because Energas' average health care cost has risen at 1.5% since 1995, while that of the industry overall has been only 3.6%, it is necessary to reduce the rate assumed in the Company's SFAS cost estimate by a minimum of 2½ percentage points, or $273,513, as recommended by Mr. Pous.[372]

The Cities also point out that the Towers Perrin survey relied upon by Ms. McDaniel is not in the record, so it cannot be verified. They argue that the Company's actual expenses and those measured by the Federal Government show that the actuaries have always overestimated the assumed medical cost trends, so they argue that Ms. McDaniel's estimations should not be used.[373]

Finally, the Cities argue that Mr. Pous' failure to include $2,302,000 of Energas' health care costs in his testimony is immaterial because he did not rely on the Company's 2000 study in preparing his testimony other than to recognize the updated discount rate.[374]

2.b.(3) *Examiners' Analysis*

The Examiners recommend that Energas' health care cost trend be utilized because Energas has provided a better basis for estimating health care cost trends than the Cities. The Examiners found Ms. McDaniel's testimony to be clear and convincing.

First, Ms. McDaniel has clearly identified the trend as increasing the last few years, and Mr. Pous' testimony does not controvert that fact. Mr. Pous claims that the Company experienced a 1.2% decrease in health care costs per employee since 1993 and a 1.5% increase since 1995. However, these are not useful in determining the overall trend. Besides citing an overall *employee* health care cost that includes items that are not part of the *retiree* health care trend, Mr. Pous' testimony does not acknowledge that the average cost increases have grown significantly larger since 1995. Ms. McDaniel testified as follows:[375]

During the mid to late 1990s, managed care programs held down health care cost trends by compressing utilization. However, trends are on the rise according to a recent Towers Perrin survey—2000 Health Care Cost Survey:

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[371] Cities' Ex. 98 at p. 59.
[372] Cities' Ex. 98 at p. 60.
[373] Cities' Reply Brief at p. 76.
[374] *Id. at* p. 77.
[375] Energas' Ex. 20 at pp. 6-7.

(a) Average Cost Increases: 1994-2000

Health Care Plan	1994	1995	1996	1997	1998	1999	2000
Retirees < 65	9%	3%	4%	4%	4%	6%	10%
Retirees 65+	8%	3%	3%	7%	5%	10%	24%

This chart clearly shows that average health care cost increases dropped from 1994 to 1995, and have been increasing since. In light of Ms. McDaniel's testimony, Mr. Pous' statistics are not useful because they do not provide the entire picture of the health cost trend year by year. Mr. Pous provides averages from 1993 to 1999 and from 1995 to 1999, but does not address what these health care costs per employee were in 1994, 1996, 1997, 1998, or 2000, or what the trend was between those years. Mr. Pous also does not explain why these limited statistics are more reliable than the Company's actuarial analysis. Therefore, the Examiners do not find Mr. Pous' recommended adjustment reliable. Ms. McDaniel, on the other hand, clearly illustrates the trend in the industry.

Second, Ms. McDaniel has updated her analysis to include the most recent information. Mr. Pous' analysis, on the other hand, suffers from a lack of updated trends, given that he did not include Energas' 2000 study in his analysis. Therefore, the Examiners find Ms. McDaniel's analysis to be more reliable for recent trends, and Mr. Pous' calculation suspect.

Third, Mr. Pous has not provided any basis to conclude that the HCFA study he uses correlates to Energas' health care cost trends. Ms. McDaniel's criticism of this study and its lack of correlation with Atmos and Energas is convincing. Therefore, the Examiners conclude that Energas has provided adequate evidence to prove the reasonableness of its health care cost trend estimates.

2.c. SFAS-106 Discount Rate

<u>Contested Issue</u>: Should Energas' 7.00% Discount Rate be approved, or should it be adjusted to 7.85%, thereby reducing costs by $146,000?

<u>Examiners' Recommendation</u>: The Examiners recommend a discount rate of 7.50%, and a negative adjustment of $86,000 to Energas' proposed SFAS-106 cost.

2.c.(1) *Energas' Position*

Energas claims that the appropriate discount rate is 7.00%, which is the rate that is associated with the data being used to set rates, from 1998. Further, Energas argues that the fact that interest rates have risen in recent months should not change the discount rate, because ratemaking is based on a test year, so piecemeal changes to the data should not be made. Ms. McDaniel did not change her report and does not release mid-year corrections, unless something monumental happens. Ms. McDaniel also testified that a new report would never be issued simply because interest rates changed.[376]

2.c.(2) *Cities' Position*

The Cities argue that Energas' proposed discount rate is outdated, and should be adjusted for known and measurable changes to 7.85%, thereby reducing costs by $146,000 ($86,000 x (35+50)/50).[377] The Cities point to the Company's latest actuarial study, dated April 2000, which reveals that Energas itself now utilizes a rate of 7.5%, which reduces SFAS-106 costs by $86,000. The Cities go further to argue that, based on Ms. McDaniel's testimony during cross examination, a discount rate of 7.85% is actually more reasonable, resulting in a reduction of SFAS-106 costs by $146,000.

2.c.(3) *Examiners' Analysis*

The Examiners recommend that a 7.5% discount rate be used, as a known and measurable change found in the Towers Perrin Report of April 2000, which uses data updated to October 1, 1999. Furthermore, the Examiners recommend the $86,000 negative adjustment as calculated by Mr. Pous.[378] Though it is unclear whether Mr. Pous' calculation uses the updated data in the October 1, 1999 Towers Perrin Report, it is the most reliable calculation of the necessary adjustment in the record, and Energas has not contested its validity.

Accordingly, the Examiners do not believe that the Cities justified a discount rate of 7.85%. The Cities cite Ms. McDaniel's testimony, where she testifies that the 30-year bond rate has increased since October 1, 1999:

> A: It changes daily.
> Q: And what has the trend been?
> A: Since October 1, 1999, it has increased.
> Q: And how many basis points has it increased? Can you give me an order of magnitude?
> A: I would guess that it has gone up 30 to 40 basis points.[379]

Though this testimony supports a higher rate than 7%, the Examiners do not think that a rate of 7.85% is a known and measurable change because (1) as Ms. McDaniel testified above, the rate changes every day, and (2) there is no definitive evidence in the record supporting a 7.85% rate, and (3) the corresponding expenses have not been updated to the present time and are unknown.

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[376] Tr. Vol. 8 at p. 162, lns. 10-16.
[377] Cities' Initial Brief at p. 84. The Cities Initial Brief reflects that the sum (35+50) is multiplied by 150. In fact, the sum is divided by 50.
[378] Cities' Ex. 98 at p. 61
[379] Tr. Vol. 8 at p. 134.

Nonetheless, the Towers Perrin April 2000 Actuarial Valuation Report is in the record which corresponds to the 7.5% discount rate.[380] Therefore, the Examiners recommend that the 7.5% discount rate be used, and recommend the negative adjustment of $86,000 to SFAS-106, as calculated by Mr. Pous. Reducing Energas' requested SFAS-106 expense of $968,188 by $86,000 results in an SFAS-106 expense of $882,188.

2.d. Transition Obligation/External Account

<u>Contested Issue</u>: Did Energas properly calculate and internally fund its transition obligation?

<u>Examiners' Recommendation</u>: Yes. Energas properly calculated and internally funded its transition obligation.

2.d.(1) *Energas' Position*

When SFAS-106 was adopted in 1993, Energas elected to amortize $12,243,300 over a twenty-year period, which was its option under that board statement.[381] This amount is the liability of the Company at the time of transition, and is called the "transition obligation."

Energas first argues that the transition obligation was correctly calculated. By recommending a reduction of the health care cost trends by 4 percentage points, Mr. Pous would change the amortization of the transition obligation.[382] On rebuttal, Ms. McDaniel testified that the Towers Perrin original calculation of the obligation was reasonably correct, and the actuaries "did a pretty good job" in 1993.[383]

In response to the Cities' charge that Energas should have externally funded its OPEB expenses, the Company argues that internal funding was approved by the Commission for Energas in GUD Nos. 8476-8541 on January 23, 1995.[384] Internal funding was also approved by the Commission for the environs of the Cities of Fritch and Sanford in GUD Nos. 8371 and 8372, on August 30, 1993. Therefore, Energas undertook internal funding of its OPEBs in full reliance on the orders of the Commission.

In response to Mr. Pous' recommendation that OPEB expenses be set to zero, Energas first argues that Mr. Pous' calculations are speculative because he attempts to back-calculate what revenues an external fund might have generated. Energas argues that reducing OPEBs by this speculative sum would be retroactive ratemaking. Therefore, Mr. Pous' attempt to affect a "remedy" should be denied as inequitable and illegal.

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[380] Examiners' Exhibit No. 1,
[381] Energas' Ex. 20 at pp. 8-9.
[382] Lubbock Ex. 98 at p. 62.
[383] Tr. Vol. 8 at p. 141, lns. 2-4; *Also See* Energas Ex. 20 at pp. 8-9; Tr. Vol. 8 at pp. 161-162.
[384] Cities' Ex. 38.

Lastly, in response to Mr. Pous' allegation that the Company's actual health care *cost trend* since 1993 has been a negative 1.2%, Energas argues that this number is misleading and inappropriate for use in evaluating OPEB costs. In fact, Ms. McDaniel testified that the transition obligation was $12,243,000 as of October 1, 1993. As of October 1, 1998, the remaining unrecognized transition obligation was $7,429,100. As of this same date, the benefit obligation was $17,264,400 and the unrecognized net loss was only $394,900.[385] As Ms. McDaniel testified, the unrecognized net loss is a good measure of the difference between the expected obligations as projected and the current measurement. The relatively small value of the unrecognized net loss (about 2% of the benefit obligation) supports the conclusion that the assumptions made in 1993 were reasonable and that no adjustment should be made.[386]

2.d.(2) *Cities' Position*

The Cities argue that Energas' transition obligation was calculated in the early 1990's, and certain assumptions used in that calculation have turned out to be wrong, including those for health care cost trends. The Company's fiscal year 1993 actuarial report estimated that a 1% change in the health care cost trend would change the interest and service costs included in the transition obligation by 9.3%.[387] The estimated health care cost trends used to calculate the Company's transition obligation started with a 10.5% level.[388] When compared with the Company's actual health care cost trend since 1993 of a negative 1.2%, the Cities claim that the Company has significantly over-recovered its transition obligation on a prorated basis.[389]

Therefore, Mr. Pous recommends a 4 percentage point reduction in the health cost trend to account for the lower health cost trend and the change in the level of employees. Mr. Pous surmised that there are 14 years remaining in the amortization period and that the Company has in effect accelerated the recovery of the transition obligation during the first 6 years. The adjustment reduces the Company's proposed SFAS-106 expense by $76,114.[390]

Mr. Pous also recommends that the Commission order the Company to recalculate the amount of the transition obligation, taking into account changes in employee levels, actual health care cost trends, and more appropriate future trend estimates.[391]

Finally, the Cities recommend that Energas be ordered to create an external fund for OPEBs. They claim that internal funding has no meaning from a ratemaking standpoint. Energas has created a balance sheet item for the over-accruals under SFAS-106, compared to actual pay-as-you go expenses. However, the Company has made no attempt to incorporate that balance sheet item as a credit to rate base. If internal funding is allowed to be continued, the Cities recommend that the rate base be offset to compensate.[392]

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[385] Energas' Ex. 20 at pp. 8-9.
[386] *Id.*
[387] Cities' Ex. 98 at p. 61.
[388] *Id.* at p. 58
[389] *Id.*
[390] *Id.* at p. 62.
[391] Cities' Ex. 98 at p. 62.
[392] Cities' Reply Brief at pp. 78-79.

2.d.(3) *Examiners' Analysis*

The Examiners recommend against all three of the Cities' suggestions. The transition obligation should not be re-calculated. Also, a retroactive adjustment for Energas' decision not to create an external fund should not be made, and Energas should not be required to establish an external fund.

The Examiners agree with Energas that the transition obligation was correctly calculated in 1993, given Ms. McDaniel's testimony that the unrecognized net loss is relatively small:

> The unrecognized net loss is a good measure of the difference between the expected obligations projected based on the October 1, 1993 assumptions and the current measurement. The relatively small unrecognized net loss supports the conclusion that the October 1, 1993 assumptions were reasonable compared to the October 1, 1998 assumptions, and if anything, the assumptions were not conservative enough in the aggregate.[393]

The Cities' argument is not convincing, given the limited usefulness of the negative 1.2% reduction in health care costs from 1993 to 1999 in determining the health care cost trend. In light of Ms. McDaniel's testimony above, and the increase in health care costs in 2000, the Examiners can find no definitive evidence in the record to demonstrate a mis-calculation of the transition obligation in 1993.

The evidence indicates that Energas legally and appropriately calculated and amortized its transition obligation in 1993. Any attempt to make a retroactive adjustment to this calculation could result in retroactive ratemaking. Therefore, the Examiners recommend that the Commission decline to make the Cities' proposed 4 percentage point adjustment and re-calculation of the transition obligation.

The Examiners further recommend that the Commission decline to order Energas to establish an external fund for its OPEB expense. The Commission allowed Energas to internally fund this expense in two previous rate cases.[394] Although the Cities point out that the Commission was careful to encourage the re-visitation of the issue in its Order in GUD Nos. 8371-8372, the Examiners are unconvinced that external funding should be ordered in this case.

The Cities argue that internal funding allows Energas to recover its over-accruals in rate base, unless a negative adjustment is made. However, in light of the Examiners' recommendations that Energas' health care cost trends and transition obligation calculation are reasonable, the Examiners see no reason to order Energas to create an external fund. The internal funding mechanism has been allowed for Energas by Commission Order, and there is no clear evidence that Energas has unfairly benefited from the internal fund. Therefore, the Examiners recommend that the Commission decline to order Energas to establish an external fund for its OPEB expense.

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[393] Energas' Ex. 20 at pp. 8-9; Ms. McDaniel reiterates her point on redirect at Tr. Vol. 8 at pp. 161-162.
[394] GUD Nos. 8476-8541 on January 23, 1995; GUD Nos. 8371 and 8372, on August 30, 1993.

3. PENSIONS (FAS 87)

Contested Issue: Should Energas be allowed to set its externally funded Pensions fund at zero for ratemaking purposes, or should the surplus be counted as a negative expense?

Examiners' Recommendation: The Examiners recommend that Energas' Pensions Fund be set at zero for determining the revenue requirement in this case.

3.a. *Energas' Position*

Energas argues that its external pension fund is accounted for on the books of the Company in accordance with Financial Accounting Standard Board Statement No. 87 (FAS 87). The external fund has outperformed its expenses, and Energas experienced a net book pension expense credit (also called a negative pension expense) of $1,102,111 in its West Texas operation during the test period.[395]

Mr. Burman testified on behalf of Energas that this negative pension expense should be set at zero for ratemaking purposes in this case, and Energas will separate out the pension fund accounts and will not seek any rate relief for pensions expense until the current negative expense turns around and becomes positive.[396] Thus, ratepayers will not see or fund any pension expense in the future so long as the rates established in the case are in effect.

Energas argues that the Cities' recommendation to credit ratepayers with $1,865,287 in the test year is "unfair to the Company, unjustly enriches ratepayers, and smacks of retroactive ratemaking."[397] Energas' concern is mainly one of cash flow; such an adjustment would "decrease the Company's cash for operations and maintenance and affect a transfer to ratepayers from the operating funds of the Company of about $1.9 million on an annual basis."[398]

Energas further argues that, even if the Commission allowed the Cities' requested "refund" on past contributions, the amount suggested by the Cities is too large, because the negative pension expense is mainly due to the terrific market performance of the nineties and a reduction in the number of eligible employees, rather than payments by ratepayers.[399] Mr. Burman testifies that ratepayers have been paying "nominal amounts" because: (1) The amounts included in rates were themselves relatively small, given the magnitude of the fund. Though Energas has had rates set with nominal pension amounts in cost of service, these cases were a result of settlements, and pension expense was not directly addressed. Since the revenue requirements in those cases were less than the requested cost of service, the amounts in the pension expense would technically be even less than requested – at most about $1,000,000 total for all eight years ended prior to the test year. (2) Warmer than usual weather has significantly

[395] Energas' Ex. 7 at p. 9.
[396] Energas' Ex. 7 at p. 9.
[397] Energas' Post-Hearing Brief at p. 75.
[398] *Id.*
[399] Energas' Ex. 20 at pp. 4-5.

hurt the Company's revenues in recent years, so "the amount that actually the customers have been paying is relatively minor in comparison to the credit that was on the books for the test period."[400]

Energas further argues that the Cities' recommendation is merely a means of taking the benefits of the market performance of the nineties from the pension fund and paying them to the ratepayers. Mr. Burman points out that under federal law, neither the Company nor the ratepayers are entitled to the benefits.[401] Rather, the benefits are accounting entries on the books of the Company and are not available to the Company. Thus, the pension "assets" should be separated out of the actual cash money needed by Energas to pay its operations and maintenance expense for ratemaking purposes, and the pension expense should be set at zero.

3.b. *Cities' Position*

The Cities argue that ratepayers have paid over $1 million in pension expense through rates in the past eight years, but Energas has not paid any contributions into the fund since 1993. Thus, Energas has been overcollecting pension costs from its customers for at least seven years.

The Cities further argue that Energas' proposed treatment of the negative pension expense is inconsistent with FAS 87, which requires accrual accounting for pension expense. Only for this negative pension expense has Energas chosen not to reflect the expense on an accrual basis, unlike OPEBs, which were treated under accrual accounting. Thus, the Company seeks to artificially increase its pension expense to eliminate the actual test year negative amount.

Mr. Pous calculated the negative pension expense by taking the Company's proposed $1,102,111 negative expense and incorporating the results of the Company's own updated actuarial study, which determined that the West Texas Division level is $1,712,274, which is $610,163 greater (i.e., more negative) than the Company's test year book amount. Finally, Mr. Pous adjusts for further reductions in employee levels after January 1, 1999, producing an additional reduction of $153,013. The total of these adjustments is a negative $1,865,287, and Mr. Pous recommends that this amount be deducted as a negative pension expense.

3.c. *Examiners' Analysis*

The Examiners agree with Energas that the appropriate means of treating this negative pension expense is to set it at zero for ratemaking purposes. This removes the pension expense from the rates that Energas is allowed to charge its ratepayers.

The Commission should not attempt to compensate the ratepayers for past payments under rates that were allowed in previous Commission Orders, because it could result in retroactive ratemaking. Therefore, the Cities' adjustments should be rejected because they unfairly punish Energas for charging rates that were fair and just when they were determined. Even though the money paid in rates for the pension expense was not all put in the pensions

[400] Tr. Vol. 4 at p. 181.
[401] Energas' Ex. 7 at p. 10; Tr. Vol. 4 at pp. 177-178.

account because of overfunding, Energas legally charged the rates, and the Commission may not retroactively compensate the ratepayers for funds that were paid under legal rates.[402] Rates are set and charged into the future, so it makes no sense to reduce Energas' operations and maintenance expense year after year for a fund that Energas cannot touch,[403] and which could turn into a positive expense due to market conditions.

Furthermore, the Examiners recommend that the Commission require Energas to continue its accrual method of accounting for the negative pension expense. In this manner, Energas can determine when this fund reaches a positive level for future ratemaking purposes. The account should be set to zero only for the purpose of setting rates in this case, not for accrual accounting purposes.

VII. CLASS COST ALLOCATION

Once the total cost of service of a utility is determined, the costs must be allocated to the various customer classes for recovery through rates. Costs are first *functionalized*, which is the process of determining whether a cost is related to the production, storage, transmission, or distribution function.[404] The costs are then *classified* as to whether they are customer-, demand-, or commodity-related, or are direct costs.[405] Finally, costs are *allocated* to the residential, commercial, industrial, and public authority customer classes.[406] Energas relies on a detailed Class Cost of Service Study (CCOS) to determine the allocation of its cost of service to its various customer classes. The Cities challenge the results of the Company's CCOS and conclude that it is fatally flawed. The Cities recommend that costs be allocated based on Energas' existing rate structure.

<u>Contested Issue</u>: How should the costs determined in this proceeding be allocated to Energas' various customer classes?

<u>Examiners' Recommendation</u>: The Examiners reject Energas' Class Cost of Service Study and recommend that costs be allocated to the Company's various customer classes based on the existing rate structure.

A. ENERGAS' POSITION

Energas witness Daniel M. Ives testified that:

> A Class Cost of Service Study (CCOS) is used to apportion a utility's total annual costs among its classes of service, such as Energas' residential, commercial,

[402] *See Railroad Comm'n of Texas v. Houston Natural Gas Corp.*, 155 Tex. 502, 289 S.W.2d 559 (1956); *Texas Ass'n. of Long Distance Telephone Companies (TEXALTEL) v. Public Utilities Comm'n of Texas*, 798 S.W.2d 875, 882 (Tex. App—Austin 1990).
[403] Tr. Vol. 4 at pp. 177-178.
[404] Energas' Ex. 16 at p. 4, lns. 9-10.
[405] Energas' Ex. 16 at p. 5, lns. 14-15.
[406] Energas' Ex. 16 at p. 4, lns. 5-6.

industrial, and public authority customer classes. The costs may be further apportioned within the classes, distinguishing between customer-related costs, capacity demand costs, commodity-driven costs and revenue costs, such as revenue-based taxes.[407]

1. FUNCTIONALIZATION

Mr. Ives prepared a CCOS for this proceeding. Using Energas' adjusted test year cost of service, he first determined to which function these costs should be assigned. He examined both rate base and expense items, and found that virtually all the costs were distribution-related. Table 1 is a summary of the functionalization factors developed by Mr. Ives:[408]

TABLE 1
Functionalization Factors

Line No.	Item	Total	Production	Storage	B. Transmission	Distribution
1	Rate Base					
2	Gas Plant	100%	0%	0%	0%	100%
3						
4	Expenses					
5	O&M	100%	0%	0.01%	0.00%	99.99%

As is evident from Table 1, virtually one hundred percent of all costs are assigned to the distribution function. The overall effect for cost classification and allocation of the production, storage, and transmission functions is less than one percent.

2. CLASSIFICATION

Next, Mr. Ives classified the costs according to their cost causality by again examining both rate base and expense items. Table 2 is a summary of the classification factors developed by Mr. Ives.[409]

[407] Energas' Ex. 16 at p. 3, lns. 10-14.
[408] Energas' Ex. 16, Exhibit DMI-1, Schedule 3 at p. 4.
[409] Energas' Ex. 16, Exhibit DMI-1, Schedule 3 at p. 5.

TABLE 2

Classification Factors

Line No.	Item	Total	Customer	Demand	Commodity	Direct
1	**Production**	100%	0%	100%	0%	0%
2	Storage	100%	0%	50%	50%	0%
3	Transmission	100%	0%	100%	0%	0%
4	Minimum System Analysis	100%	76.31%	23.69%	0%	0%
5	**Distribution – Total**	100%	84.60%	14.59%	0%	0.81%
6	Distribution – w/o Direct	100%	85.29%	14.71%	0%	0%
7	Customer Only	100%	100%	0%	0%	0%
8	Demand Only	100%	0%	100%	0%	0%
9	Commodity Only	100%	0%	0%	100%	0%
10	Direct Assignment	100%	0%	0%	0%	100%

Mr. Ives began with the classification of rate base costs through an analysis of distribution plant. In his analysis, he first assigned industrial measuring and regulating station equipment directly to the Industrial customer class, as it is customer-specific.[410] Remaining distribution costs were assigned according to two factors – assignment of customer-only costs and assignment of costs based on a minimum system analysis. Customer-only costs include costs for services, meters, regulators and related equipment that are incurred specifically to serve customers.[411]

The minimum system analysis, also called the Minimum Mains Study, is a method used to determine the allocation of distribution costs between Customer and Demand classifications. The method resizes (and reprices) all mains footage greater than 2 inches in diameter to the minimum system size of 2 inches (the size generally required to serve the smallest customer class – Residential). The resulting cost of the minimum system is allocated to the Customer component because it represents the theoretical system that would serve the minimum Residential gas demand. The difference between the actual system cost and the derived minimum system cost is allocated to the Demand component because it serves the peak demand of the distribution system. The detail plant records of the West Texas system were unusable because they were being converted from a manual ledger system at the time the study was prepared, so data for Energas' Amarillo system was used as a surrogate in the minimum system analysis.[412]

[410] Energas' Ex. 16 at p. 6, lns. 7-8.
[411] Energas' Ex. 16 at p. 6, lns. 4-5.
[412] Energas' Ex. 16 at p. 5, lns. 22-31.

Energas pointed out that the use of a minimum distribution system analysis is recognized as a valid cost allocation methodology. The Company cited the Public Utility Commission of Texas, the Virginia State Corporation Commission, and the District of Columbia Public Service Commission as regulatory agencies that have adopted the use of a minimum distribution system methodology to allocate system costs and for determining the level of monthly customer charges.[413]

Mr. Ives testified that using Amarillo data as a surrogate was reasonable because he had "no reason to believe that, in total, the data for the distribution systems in the West Texas cities and towns served by Energas would produce results materially different than the data for the distribution system in the City of Amarillo."[414] Mr. Ives also noted that he compared the results of his minimum distribution system study with the results of a study he performed in Illinois, and found them similar. The results of the West Texas study using Amarillo data yielded an allocation of 76.3 percent of distribution costs to the customer component, while his Illinois study yielded an allocation of 77 percent to the customer component.[415]

Mr. Ives continued with the classification of Operating and Maintenance (O&M) expenses. The majority of these costs were classified as Customer or Demand based on a Customer-only allocation or an allocation between Customer and Demand using a Distribution Plant Allocator derived from the distribution plant analysis. This Allocator assigns 85.29 percent of the subject costs to the Demand classification.[416]

3. ALLOCATION

Finally, Mr. Ives allocated costs to Energas' various customer classes. Table 3 is a summary of the allocation factors developed by Mr. Ives.[417]

[413] Energas' Initial Brief at p. 106.
[414] Energas' Ex. 22 at p. 12, lns. 20-23.
[415] Tr. Vol. 5 at p. 188, lns. 13-21.
[416] Energas' Ex. 16 at p. 6, lns. 11-17.
[417] Energas' Ex. 16, Exhibit DMI-1, Schedule 3 at p. 6.

TABLE 3
Allocation Factors

Line No.	Item	Total	Residential	Commercial	Industrial	Public Authority
1	**Customers**	100%	90.85%	8.50%	0.20%	0.44%
2	Customers weighted by service inv.	100%	79.48%	18.60%	0.60%	1.32%
3	Customers weighted by meter inv.	100%	79.13%	17.77%	0.96%	2.13%
4	Sales Volume	100%	65.60%	19.94%	7.39%	7.07%
5	**Total Volume**	100%	61.61%	18.72%	13.03%	6.64%
6	Peak Day Volume	100%	68.45%	21.34%	3.40%	6.81%
7	Average & Peak Factor	100%	67.73%	20.98%	4.41%	6.88%
8	Total Rate Base	100%	82.52%	13.93%	1.70%	1.86%

Mr. Ives allocated rate base after separating it into four components: Mains (acct 376), Services (acct 380), Meters (accts 381-384), and Other Distribution Plant. The Customer component of Mains was allocated using number of customers, while the Demand component was allocated using peak day volume.[418]

Services were allocated based on number of customers weighted to reflect the relative service investment by customer class. Mr. Ives conducted a Services Investment Study to determine the relative investment in service lines for each customer class. The presumption is that higher volume customers will require larger sized service lines. As with the minimum system study, data for Energas' Amarillo system was used as a surrogate in the Services Investment Study because the West Texas detail plant records were being converted from a manual ledger system at the time the study was prepared.[419]

Meters were allocated based on number of customers weighted to reflect the relative meter investment by customer class. Mr. Ives conducted a Meter Investment Study to determine the relative investment in meters for each customer class. The presumption is that meters, like service lines, are sized to meet customer flow requirements. The Meter Investment Study was based on a five-city proxy (Lubbock, Midland, Odessa, Plainview, and Big Spring) because

[418] Energas' Ex. 16 at p. 6, lns. 21-23.
[419] Energas' Ex. 16 at p. 6, ln. 25 - p. 7, ln. 4.

detailed plant records were being converted from a manual ledger system at the time the study was prepared and were not available for all cities in the West Texas System.[420]

The Customer component of the fourth part of rate base, Other Distribution Plant, was allocated to the various customer classes using number of customers, while the Demand component was allocated using peak day volume.[421]

Mr. Ives allocated seven categories of O&M to Energas' customer classes. These categories and their allocation methodology are summarized in Table 4.[422]

TABLE 4
Expense Allocation Methodologies

Line No.	**Item**	**Methodology**
1	**Functional O&M Expense**	
2	**Customer**	No. of Meter-Weighted Customers
3	**Demand**	Peak Day Volume
4	**Customer Accounts & Service Expense**	No. of Customers
5	Sales Expense	No. of Customers
6	A&G Expense	Same as Functional O&M
7		
8	Interest on Customer Deposits	Sales Volume
9	Depreciation Expense	Total Rate Base
10	Property & Other Taxes	Total Rate Base

Finally, return was calculated based on allocated rate base, and income taxes were calculated on the return.[423]

Energas argues that its proposed allocation of cost of service is reasonable and produces returns by class that reflect a movement toward elimination of the subsidy of the Residential class by other customer groups.[424]

B. CITIES' POSITION

The Cities argue that Energas' Class Cost of Service Study is fatally flawed, so flawed that it does not rise to the level of engineering art. The Cities point out that a vast majority of the distribution plant in this proceeding is classified by use of the minimum distribution mains study. The Cities assert that the minimum mains study is unreliable as far as providing any support for

[420] Energas' Ex. 16 at p. 7, lns. 6-15.
[421] Energas' Ex. 16, Exhibit DMI-1, Schedule 4 at p. 9.
[422] Energas' Ex. 16, Exhibit DMI-1, Schedule 7 at p. 13.
[423] Energas' Ex. 16, Exhibit DMI-1, Schedule 5 at p. 10.
[424] Energas' Ex. 16 at p. 8, lns. 15-17.

increasing the size of the customer charge.[425] The Cities' alternative is to allocate proportionately any change in revenue requirement to each component of the Company's existing tariffs.[426]

The Cities argue that there is no evidence in the record to support using Amarillo as a proxy for the entire West Texas distribution system in the minimum system study.[427] They point to Mr. Ives' own testimony on the Non-Unanimous Agreement (NUA) that the West Texas and Amarillo systems cannot be compared. He testified that "Amarillo's rates are set on the basis of Amarillo's costs."[428] Further, Mr. Ives stated that the cost per residential customer in Amarillo was lower than the cost per customer in West Texas, in part because of "the greater customer density of the Company's Amarillo service area in comparison to its much more spread out West Texas service area."[429] Mr. Ives also testified on cross-examination that customer density would impact the configuration of the distribution system, and may have an impact on a minimum distribution study.[430] Lastly, the Cities observe that Mr. Ives' Meter Investment Study only relied on data from five West Texas Cities, again bringing into question the validity of the study's results.[431]

The Cities point out that, while the Company referred to several regulatory agencies that have adopted the minimum system analysis as reasonable, others have rejected the methodology. Cities note that the Illinois Commerce Commission, before which Mr. Ives has filed testimony, has rejected the use of the minimum system analysis to allocate costs.[432] The Maryland Public Service Commission, with regulatory authority over a previous employer of Mr. Ives, has also rejected the minimum system analysis methodology.[433] The Cities clarify that, in the Texas PUC case cited by the Company, most of the distribution plant was <u>not</u> allocated using a minimum distribution system methodology.[434]

The Cities dispute Mr. Ives' assertion that the results of his minimum system study were reasonable because its results were similar to a study performed in Illinois. The Cities state that there is nothing in the record about how Mr. Ives prepared the Illinois study, and about what size pipe he used as the minimum. There is also nothing in the record about the geographic nature or population density of the Illinois system, "other than Mr. Ives thought that Kankakee was in the service territory."[435] The Cities further argue that the fact that the results of the two studies yielded similar results indicates the ease with which the data can be manipulated, especially if the characteristics of the two systems are different.[436]

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[425] Cities' Initial Brief at p. 120.
[426] Cities' Ex. 97 at p. 78, lns. 6-8.
[427] Cities' Initial Brief at p. 120.
[428] Energas' Ex. 23 at p. 11.
[429] Energas' Ex. 23 at p. 11.
[430] Tr. Vol. 5 at p. 181, ln. 24 – p. 182, ln. 16.
[431] Cities' Initial Brief at p.123.
[432] *Northern Illinois Gas Company*, 103 PUR 4th 290, 298-299 (Ill. C.C. 1989).
[433] *Baltimore Gas and Electric Company*, 111 PUR 4th 498, 501 (Md. PSC 1990).
[434] Cities Reply Brief, p. 103, citing to *Application of Texas Utilities Electric Company for Authority to Change Rates*, Docket No. 11735, 20 PUC BULL 1029, 1258 (May 1995).
[435] Tr. Vol. 5 at p. 188.
[436] Cities' Initial Brief at p. 121.

The last argument presented by the Cities is that Mr. Ives failed to use the minimum pipe size in his minimum system study. While he assumed 2-inch pipe in his study, there is actually a small amount of distribution pipe less than 2 inches in the Amarillo system, and in the West Texas system as well.[437] When asked why he used 2-inch pipe rather than 1 or 3-inch pipe in his analysis, he did not know.[438] So, even if he had the West Texas data, he had no basis for using 2-inch pipe in his study. An engineering analysis is required to determine the appropriate minimum pipe size, and such a study was not presented in this proceeding.[439] Mr. Ives makes it clear that he is not an engineer.[440] If Mr. Ives had used 1-inch pipe in his minimum system study, then the amount of the Amarillo distribution mains that would have been allocated to the customer component would have been about 15 percent rather than 76 percent.[441] The Cities calculation of this is presented in Table 5.[442]

The Cities conclude that, because Mr. Ives did not have West Texas system data, he could not know how much of the system contained pipe less than 1 inch, and therefore there was no way he could undertake a reliable minimum distribution system study for the West Texas system.[443]

TABLE 5
Distribution Mains Study

Line No.	Size	Feet	$	$ per Foot
1	<2”	25,347	14,989	0.591
2	2”	2,617,042	7,992,150	3.054
3	3”	1,076,138	3,577,453	3.324
4	4”	819,772	4,240,456	5.173
5	5”	0	0	0
6	6”	394,549	1,627,723	4.126
7	8”	233,152	930,785	3.992
8	10”	38,296	767,926	20.052
9	12”	148,359	2,187,800	14.747
10				
11	Total	5,352,655	21,339,282	3.987

[437] Tr. Vol. 5 at p. 185, lns. 6-23.
[438] Tr. Vol. 5 at p. 187.
[439] Cities’ Reply Brief at p. 108; Tr. Vol. 5 at p. 187.
[440] Tr. Vol. 5 at p. 186, ln. 1, p. 187, lns. 5-6.
[441] Cities’ Initial Brief at pp. 122-123.
[442] Derived from Energas Ex. 16, Exhibit DMI-1, Schedule 11 at p. 17.
[443] Cities’ Initial Brief at p. 123.

Energas Calculation for 2-Inch Minimum System

Line No.	Size	Feet	$	$ per Foot
1	Total > 2”	2,710,266	13,332,143	4.919
2	@ 2” Price	2,710,266	8,276,846	3.054
3	Difference	2,710,266	5,055,297	1.865

Energas Minimum System

Demand:	$5,055,297	23.69%
Customer:	$16,283,985	**76.31%**

Cities Calculation for 1-Inch Minimum System

Line No.	Size	Feet	$	$ per Foot
1	Total > 1”	5,327,308	21,324,293	4.003
2	@ 1” Price	5,327,308	3,150,314	0.591
3	Difference	5,327,308	18,173,979	3.411

Cities Minimum System

Demand:	$18,173,979	85.17%
Customer:	$3,165,303	14.83%

C. EXAMINERS’ ANALYSIS

The Examiners recommend that the Commission reject the Company’s class cost allocation because it uses Amarillo proxy data for the Class Cost of Service Study (CCOS), and the Company has not demonstrated why it was reasonable to do so.

The Company presented a Class Cost of Service study that sought to methodically allocate costs to those customers for which those costs were incurred. The Company’s “bottom up” approach indicates that a large majority of costs were incurred by the Residential class, and that most of these costs, in fact, did not vary with natural gas throughput. On the other hand, the Cities present compelling evidence that the portion of the CCOS (the minimum system study), from which many of the allocations were determined, is flawed.

The Examiners agree with the Cities that the minimum system analysis cannot be relied on to determine allocation factors in this proceeding. The Examiners concur with the Cities that there are enough differences between the Amarillo system and the West Texas system to require a showing that the Amarillo proxy data reasonably represented the West Texas system. The Company did not meet its burden of proof in this regard.

The Examiners refer to the record to show that differences do exist between the two systems. For example, the Cities point out that Amarillo has a higher customer density than does the West Texas system, and the Company's witness, Mr. Ives, agreed that density can impact the design of a distribution system.[444]

Mr. Ives' testimony that he had no reason to believe that the systems were different falls short of the evidence necessary to show that the Amarillo distribution system is an accurate proxy for the West Texas system.[445] Energas pointed out in its reply brief that West Texas data were partially available to Mr. Ives and could be and, in fact, were used as a check on the Amarillo data.[446] Yet, the only evidence in the record of this "check" is that Mr. Ives determined that both the West Texas and Amarillo distribution systems contained *de minimus* amounts of 1-inch pipe.[447]

It is curious that the Company was able to use data from five West Texas system cities to perform its meter investment study, but was not able to use this data for its minimum distribution system study. The Examiners believe that a minimum system study prepared with data from the same five West Texas system cities may yield more reliable results than a study based on data from outside the system. However, even that study would require an evidentiary foundation that the five cities constituted a valid proxy for the entire 67-city system.

Although the Amarillo minimum distribution study is not the basis for allocating the entire cost of service, it represents a significant portion of it. For example, $98.3 million of the $159.6 million of distribution plant on Energas' books (62 percent) was classified according to the results of the minimum system analysis that used Amarillo data as a proxy.[448] Further, $4.2 million of the $8.4 million (50 percent) of the distribution-related O&M expenses were classified using the Distribution Plant Allocator, which is derived from the same minimum system study.[449]

In short, Mr. Ives presented a Class Cost of Service study that would be relevant if this Commission was deciding rates for the City of Amarillo - but the Commission is deciding rates for the West Texas system. Therefore, the Examiners recommend that the revenue requirement determined in this proceeding be allocated proportionately to each component of the Company's existing tariffs to determine new rates. This methodology is proposed by the Cities and is the only credible alternative in the record.

The Examiners note that Energas claims that present rates are not cost-based and are considerably skewed from being cost-based. The Company attempts to support this assertion by

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[444] Energas' Ex. 23 at p. 11.
[445] Energas' Ex. 22 at p. 12, lns. 20-23.
[446] Energas' Reply Brief at p. 86.
[447] Tr. Vol. 5 at p. 195, lns. 13-23.
[448] Energas' Ex. 16, Exhibit DMI-1, Schedule 10 at p.16.
[449] Energas' Ex. 16, Exhibit DMI-1, Schedule 6 at p. 11.

pointing to both the outcome of its minimum distribution study and its calculation of the relative rates of return of the various customer classes, a calculation that is based on the outcome of the minimum distribution study.[450] This is a circular argument; it is the very outcome of the minimum system study that is challenged.

VIII. RATE DESIGN

As discussed in the Class Cost Allocation Section of this PFD (Section V.), a process of cost functionalization, classification, and allocation is required to allocate the utility's costs to the various customer classes for recovery through rates. *Rate design* is the process of determining how non-gas costs will be recovered from a particular rate class. A typical rate will include a fixed monthly customer charge, as well as a commodity usage rate. Gas costs are also recovered through a commodity rate that varies monthly with the cost of gas.

A. DESIGN BASED UPON CCOS

Energas proposes a rate design that incorporates a declining block commodity usage rate and a fixed monthly customer charge to recover fixed costs of the Company. The Cities argue that the Company's rate design is based on the results of its flawed Class Cost of Service (CCOS) study and therefore cannot be relied on. The Cities recommend that rate design be based on Energas' existing rate design structure.

Contested Issue: How should the rate design in this proceeding be determined for Energas' various customer classes?

Examiners' Recommendation: The Examiners reject Energas' rate design based on its Class Cost of Service Study and recommend that rate design be based on the Company's existing rate design structure. Also, the Examiners recommend approval of Energas' request to remove gas costs from base rates.

1. ENERGAS' POSITION

Mr. Ives designs rates based on the results of his Class Cost of Service (CCOS) study, which was explained in the Class Cost Allocation Section (Section V.) of this PFD. He explains that Energas currently utilizes a declining block rate design for recovery of its non-gas costs through commodity usage rates and it also charges a monthly customer charge to recover fixed costs of the Company. Under a declining block rate design, non-gas commodity usage rates decline as the customer's usage increases through successive pricing blocks. As the customer increases its use of the facilities (its load factor), it pays less per unit of gas consumed. The Company recovers most of its fixed costs in the initial usage blocks, along with its monthly customer charge.[451]

[450] Energas' Reply Brief at p. 83.

[451] Energas' Ex. 16 at p. 9, lns. 11-22.

The Company proposes continued use of the declining block rate design and monthly customer charge, but modified to reflect the results of its CCOS study. The Company also proposes to remove gas costs from its commodity rates by setting the base cost of gas to zero in its base rates.[452] Table 1 is a summary of the rates proposed by Energas, compared to current rates (excluding cost of gas).[453]

[452] Energas' Ex. 16 at p. 9, ln. 25 – p. 10, ln. 1.
[453] Energas' Ex. 16, Exhibit DMI-2 at p. 10-16.

TABLE 1
Energas' Existing and Proposed Rates
(excluding cost of gas)

		Existing		Proposed	
Line No.	Class	Range (mcf)	Rate	Range (mcf)	Rate
1	Residential				
2	Customer Charge		$6.50		$9.00
3	1st Block	1 – 4	$1.080	1 – 5	$1.230
4	2nd Block	5 – 10	$1.040	6 – 15	$1.105
5	3rd Block	11 – 50	$1.010	16 – 25	$0.980
6	4th Block	>50	$0.990	>25	$0.905
7	Commercial				
8	Customer Charge		$6.50		$13.00
9	1st Block	1 – 4	$1.080	1 – 10	$1.180
10	2nd Block	5 – 10	$1.040	11 – 40	$1.080
11	3rd Block	11 – 50	$1.010	41 – 80	$0.930
12	4th Block	>50	$0.990	>80	$0.855
13	Public Authority				
14	Customer Charge		$6.50		$28.50
15	1st Block	1 – 4	$1.080	1 – 50	$1.180
16	2nd Block	5 – 10	$1.040	51 – 250	$1.080
17	3rd Block	11 – 50	$1.010	251 – 500	$0.905
18	4th Block	>50	$0.990	>500	$0.830
19	State Institutions				
20	Customer Charge		$6.18		$27.08
21	1st Block	1 – 4	$0.890	1 – 50	$0.980
22	2nd Block	5 – 10	$0.850	51 – 200	$0.890
23	3rd Block	11 – 50	$0.820	201 – 400	$0.720
24	4th Block	>50	$0.800	>400	$0.650
25	Industrial				
26	Customer Charge		$28.50		$38.50
27	1st Block	1 – 50	$0.730	1 – 100	$0.880
28	2nd Block	51 – 100	$0.670	101 – 300	$0.730
29	3rd Block	>100	$0.640	301 – 600	$0.680
30	4th Block			>600	$0.655
31	Large A/C				
32	Customer Charge		$0.00		$0.00
33	1st Block	All	$0.640	All	$0.655
34	Residential A/C				
35	Customer Charge		$6.50		$8.50
36	1st Block	1 – 2	$1.080	1 – 5	$1.230
37	2nd Block	>2	$0.640	>5	$0.655

The Company proposes to split the current General Service rate into separate Residential, Commercial, and Public Authority rate classes in recognition of the different consumption characteristics of these customers.[454]

Mr. Ives' goals in developing the Company's proposed rates are four-fold: first, to generate additional revenues; second, to recover these revenues in proportion to the results of the CCOS Study; third, to maintain the existing rate structure; and fourth, to redesign the block breaks and pricing differential to better reflect the consumption patterns of each rate class.[455]

Mr. Ives testifies that the current block rate structure places too much of the Company's revenues at weather risk. For example, he explains how the current rate design recovers 12.2 percent of Residential revenues and 23.5 percent of Residential volumes in the 3rd and 4th rate blocks under normal weather conditions, while Energas' proposed rate design would recover 4.9 percent of revenues and 10.8 percent of volumes in the 3rd and 4th rate blocks under normal weather.[456] The proposed blocks are intended to allow the Company to recover its costs with less sensitivity to weather.[457]

Further, Mr. Ives revises the monthly customer charge for each class to recover costs that are fixed and incurred every month, regardless of whether gas is consumed by the customer. The revised customer charges are based on the customer component of fixed costs derived from the CCOS study.[458] The Company employs the concept of "gradualism" to adjust the customer charges indicated by the CCOS study in order to balance the indicated cost causation with the level of the existing customer charges.[459] Table 2 compares the existing customer charge for each class, the customer charge indicated by the CCOS Study, and the customer charge proposed by the Company.[460]

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454 Energas' Ex. 16 at p. 12, ln. 15 – p.14, ln. 11.
455 Energas' Ex. 16 at p. 10, ln. 14 – p. 11, ln.11.
456 Energas' Ex. 16 at p. 12, lns. 1-12.
457 Energas' Ex. 16 at p. 13, lns. 5-6.
458 Energas' Ex. 16 at p. 14, ln. 26 – p. 15, ln.11.
459 Energas' Ex. 22 at p. 10, lns. 20-22.
460 Energas' Ex. 16, Exhibit DMI-7 at p. 1-8.

TABLE 2
Comparison of Customer Charges

Line No.	Class	Existing	CCOS Study	Proposed
1	Residential	$6.50	$11.27	$9.00
2	Commercial	$6.50	$18.44	$13.00
3	Public Authority	$6.50	$31.09	$28.50
4	State Institutions	$6.18	-	$27.08
5	Industrial	$28.50	$37.67	$38.50
6	Large A/C	$0	-	$0
7	Residential A/C	$6.50	-	$8.50

Finally, Mr. Ives proposes to remove any cost of gas from base tariff rates, so that the Company's tariff rates reflect only the non-gas costs associated with delivery of gas to the customer. The Gas Cost Adjustment (GCA) will recover the Company's total cost of gas and related taxes.[461] Mr. Ives proposes this change for three reasons: first, customers will receive clearer price signals as to the commodity cost of gas; second, it is a necessary step if the Company exits the merchant function or opens its system to transportation; and third, it is appropriate to make this change concurrent with other rate design changes proposed in this proceeding.[462]

2. CITIES' POSITION

Cities argue that Energas' proposed rate design reflects dramatic increases in customer charges, including a 100 percent increase for commercial customers and 38 percent increase for residential customers. In addition, Energas proposes to reduce commodity charges in end usage blocks up to 14 percent for commercial customers and 9 percent for residential customers.[463] Cities attribute these changes to the results of the minimum system analysis contained in the CCOS study, which it argues is fatally flawed and should be given no weight in the rate design process.[464] Cities recommend that any change in revenue requirement be spread proportionately to each component of each tariff.[465]

Cities observe that the proposed rates and billing structure place more of a burden for the Company's revenue requirement on low use customers, while large use customers will see a rate reduction or smaller rate increase.[466] Cities note that gas costs have risen substantially since last

[461] Energas' Ex. 3 at p. 8, lns. 1-7.
[462] Energas' Ex. 16 at p. 15, ln. 18 – p. 16, ln. 4.
[463] Cities' Ex. 98 at p. 76, ln. 16 – p. 77, ln. 2.
[464] Cities' Ex. 98 at p. 77, lns. 10-15.
[465] Cities' Ex. 98 at p. 78, lns. 6-8.
[466] Cities' Initial Brief at p. 125.

winter (50 percent higher), and are not expected to come down for this winter heating season. Therefore, the customers' base rate increase will be in addition to the increase in gas costs.[467]

In addition, the Cities express concern that the proposed rate design is poor public policy since it encourages gas consumption at a time when gas prices are spiking. They argue that this is especially true at a time when increased demand for natural gas is contributing to significant increases in the price of gas.[468]

Finally, Cities argue that there is no load research study in the record to support the changes in residential or commercial rates in the declining blocks from the current rate structure. Such a study is necessary to support making the rate of decline between blocks more extreme. The Company has failed to provide any study to show that it is cheaper to serve customers in succeeding blocks, as proposed by the Company.[469] The Cities claim that the Company also fails to provide elasticity studies to support the break points under the new rate design, as described in *District of Columbia Natural Gas*:[470]

The Commission finds that the implementation of declining block rates requires detailed information on marginal cost and demand elasticities of all customer classes to set proper blocking points. The Company has failed to provide such evidence. Without such evidence, the Commission lacks a reasonable basis upon which to consider the blocking points, which are crucial to rate design.[471]

3. EXAMINERS' ANALYSIS

Based on the Examiners' earlier recommendation (see Section V.) to reject the Company's cost allocation methodology, the Examiners also recommend rejection of the Company's rate design methodology and support the Cities' proposal to spread the revenue requirement decided in this proceeding proportionately to each component of each existing tariff. Examiners' Schedule H reflects the application of this recommendation to the Company's customer classes.

Although Energas again presented a thorough and complete rate design proposal, it is nonetheless based predominately on the flawed Class Cost of Service (CCOS) study. The Company's minimum system analysis is the most significant driver for the level of costs allocated to the various customer classes and between customer charge and commodity charge. And, since the minimum system analysis cannot be relied on to determine allocation factors in this proceeding, then the resulting rate design components likewise cannot be relied on.

The Examiners do not dispute Energas' attempt to minimize the impact on its revenues brought about by the risk of weather that is warmer (or colder) than normal. In fact, the

[467] Cities' Initial Brief at pp. 125 - 126.
[468] Cities' Initial Brief at pp. 129 - 130.
[469] Cities' Initial Brief at p. 133.
[470] Cities' Reply Brief at pp. 111-112.
[471] *District of Columbia Natural Gas*, Order No. 8975, 91 PUR 4th 437, 473 (D.C. PSC, 1988).

Commission recently acknowledged this goal in the TXU Pipeline city gate rate case, where the Examiner adopted Staff's rate design proposal because it recognized the Company' desire to reduce its risk while protecting the consumer from bearing close to 100 percent of the risk.[472] However, the Commission cannot presume that the proposed rates are reasonable if the Company's support for the rates (the CCOS study) is not reasonable.

The rate design inherent in the existing approved rates of the Company is reasonable, as the rates have previously been found so by the appropriate regulatory authority, and can be relied on as the basis to set rates in this proceeding.

The Examiners also recommend that Energas' proposal to remove the commodity cost of gas from base rates be approved. The Examiners agree that this proposal is reasonable, will provide clearer gas price signals to consumers, and is consistent with Commission Substantive Rule 7.55 – Gas Cost Recovery.[473] The Company will appropriately recover its entire cost of gas through its Gas Cost Adjustment factor.

B. Steel Pipe Improvement Program (SPIP)

Energas proposes a rider (a surcharge) to cover the costs of its Steel Pipe Improvement Program (SPIP). The SPIP is a safety-related program through which the Company has been and continues to replace or protect approximately 1,491 miles of known cathodically unprotected steel mains on Energas' system.[474]

Contested Issue: Should Energas' SPIP Rider be approved?

Examiners' Recommendation: No. The Examiners recommend denial of Energas' SPIP Rider.

1. ENERGAS' POSITION

Energas claims that it has already replaced or protected over 780 miles of the 1,491 miles of pipe on the mains in question by February 1999. The estimated cost to complete the program in Energas' West Texas service area is approximately $23.5 million over an eight-year period.[475] Energas claims that the SPIP Rider recognizes the poor cash-flow of the Company in recent years as well as the demand for capital placed on the Company by system growth and investments such as its technology program—a necessary program to replace aged seventies vintage technology—and provides Energas with increased capital and an opportunity to more timely recover its investment in system safety.[476]

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[472] Tex. R.R. Comm'n, *Statement of Intent to Change the City Gate Rate of TXU Lone Star Pipeline Established in GUD No. 8664,* , GUD No. 8976, Revised Proposal for Decision at p. 122.
[473] 16 TEX. ADMIN. CODE § 7.55 (West 2000).
[474] Energas' Post-Hearing Brief at p. 110; *See generally,* Energas Ex. 16 at pp. 16-18.
[475] Energas' Ex. 16 at p. 16, lns. 9-17.
[476] *Id.* at lns. 19-24.

The SPIP Rider would recover "[o]nly costs associated with capital improvement projects identified in the SPIP plan" through an initial monthly charge of nine cents per bill.[477] This charge would be subject to change on an annual basis, depending on levels of SPIP revenue collections, actual SPIP investment, and estimated SPIP costs for the next year.[478]

In order to insure that Energas recovers from ratepayers only those expenditures associated with the SPIP plan, Energas points out that the SPIP rider is subject to annual review and true-up by the appropriate regulatory authority.[479] This annual review will insure that ratepayers are charged only that level of cost actually expended by the Company and are given proper credit for the amount of plant retired for purposes of calculating SPIP depreciation expense, property tax expense, and return.[480]

Energas notes that the SPIP Rider is similar to riders approved in other jurisdictions for system safety, including Arkansas and Alabama.[481] Mr. Ives testified that the SPIP establishes a stable funding platform for an important safety program that is independent of the uncertainties associated with the establishment of rates and the recovery of costs in a warm weather pattern.[482] Also, the ratepayers are protected because the Company must file annual reports explaining in detail how money has been spent and collected in the program.[483]

Energas takes issue with Mr. Lawton's claim that the SPIP is an "automatic adjustment" which will result in excess collections and which doesn't take decreasing costs into account.[484] Energas claims that the SPIP is not an automatic adjustment clause because proposed tariff page 415(A) requires regulatory approval before initial implementation of any SPIP changes. Also, proposed tariff page 17(A) requires regulatory approval before implementation of revised SPIP charges.[485] Proposed tariff page 416(A) requires the Company to file annual reports reconciling SPIP investments, related retirements, revenues, and expenses.[486]

Energas argues that Mr. Lawton's complaint about excess recovery is flawed because he assumes that everything else is equal, which is nearly impossible. Also, the SPIP would reconcile those costs and revenues related to the rider, thus considering both decreases and increases in those relevant costs, as Mr. Lawton acknowledges.[487]

Further, Energas responds to the Cities' charge that the SPIP has been discontinued and nobody knows when it will be restarted.[488] Energas points out that the proposed tariff includes a monthly charge of $0.09 per bill, set to begin on January 1, 2000: "the initial SPIP charge shall

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[477] Energas' Ex. 16 – attached tariff sheet 415(A).
[478] Energas' Post-Hearing Brief at p. 110.
[479] *Id. at* p. 111.
[480] *Id.*, *See* Original Page 416(A) and Energas' Ex. 16 at p. 18, lns. 1-10.
[481] *Id. At* p. 18, lns. 13-20. Tr. Vol. 5 at pp. 200, ln. 9 – 201, ln. 8.
[482] Tr. Vol. 5 at p. 199, lns. 5-17.
[483] Energas' Post-Hearing Brief at p. 111.
[484] Cities' Ex. 91 at pp. 26-27.
[485] Energas' Ex. 22 at p. 3, lns 14-23.
[486] *Id at* pp. 3-4.
[487] Energas' Ex. 36 at p. 63, lns. 9-11.
[488] Energas' Reply Brief at p. 93; Cities Initial Brief at p. 135.

be based on estimated costs associated with estimated Eligible Investment for the plan's first year."[489]

Finally, Energas responds to the Cities' charge of piecemeal ratemaking by arguing that the SPIP "is an incremental pricing mechanism to reflect future expenditures not reflected in nor part of the costs upon which rates were set."[490]

2. CITIES' POSITION

The Cities argue that the SPIP tariffs should not be approved because the program is too vague and speculative to provide a basis for the establishment of the rider. The program was initiated in 1993 and by February 1999, the Company had replaced 106.1 miles of steel mains and had cathodically treated another 680.6 miles of steel mains, spending $37.5 million.[491] Energas further estimates that it will spend $23.5 million over the next eight years to complete the program, without giving details regarding how much steel pipe will be replaced versus the amount of steel pipe that will be cathodically treated. Also, since there is no testimony specifying when the program will be restarted, the program is too speculative, and "would set in motion the prospect of piecemeal ratemaking."[492]

The Cities also point out that the SPIP Rider is not included in the Non-Unanimous Settlement Agreement (NUA), nor was it included in the Amarillo settlement.[493] Energas has not requested it for the Dalhart or the Sanford/Fritch Division. Instead, Energas proposes to apply the SPIP Rider only to the eight Non-Settling Cities.

Finally, the Cities argue that the Commission should not authorize this surcharge unless there is some clear financial necessity shown by the requesting utility. To do so would establish a precedent to implement surcharges without any attempt to match the surcharges with costs that are declining in value, and would be piecemeal and one-sided.[494] The Cities take issue with Energas' claim that it needs the SPIP because of the demand for capital for "system growth and investments such as its technology program."[495] Rather, the Cities point out that Atmos' huge capital investments are over, since the $130 million spent for Oracle and the IT projects came to an end some time in 1999 or early 2000: "Routine capital expenditures are down by $22 million or 30% compared to the prior year due to the fact that we did complete our technology investments in fiscal 1999."[496] The Cities quote a Moody's Press Release: "Atmos capital expenditures should now fall to maintenance levels, which should be comfortably financed through its internal cash flow. This leaves Atmos with enough financial flexibility to use any excess cash to pay down the debt or for any other uses."[497] Thus, there is no evidence in the record to show that pipeline safety is threatened because of Atmos' acquisitions in the past.

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[489] Energas' Ex. 16, Tariff Original Page No. 415(a).
[490] Energas' Reply Brief at p. 94.
[491] Cities' Initial Brief at p. 134; Energas Ex. 16 at p. 16.
[492] Cities' Initial Brief at p. 135.
[493] Tr. Vol. 5 at pp. 171, 197.
[494] Cities' Reply Brief at p. 114.
[495] Cities' Initial Brief at p. 113; Energas Post-Hearing Brief at p. 110.
[496] Cities' Ex. 5 at p. 13. (Atmos' July 28, 2000 third quarter financial results conference call).
[497] Energas' Ex. 27 at pp. 1-2.

Rather, the evidence shows that Energas spent $35 million for SPIP between 1993 and 1999, and forecasts spending $23.5 million for the next eight years.[498]

3. EXAMINERS' ANALYSIS

The Examiners recommend denial of the SPIP Rider. Though the Examiners recognize the need for safety improvements, Energas has not demonstrated that it requires such funding through a special rider or surcharge. Instead, the amount spent on such plant items in the test year is included in the rate base, and Energas is allowed to earn a return on it.

The evidence indicates that Energas has no pressing need for an up-front guarantee that the cash for these improvements may be immediately extracted from the ratepayers. Rather, the evidence shows that Energas spent $35 million for SPIP between 1993 and 1999, and forecasts spending $23.5 million for the next eight years.[499] At the same time, Atmos spent $130 million for the Oracle and the IT projects, which came to an end some time in 1999 or early 2000.[500] Thus, both the Atmos Energy third quarter financial results from July 28, 2000 and the Moody's Press Release, cited by the Cities, appear credible, and indicate that Atmos should have no "cash crunch."[501] Therefore, Energas should be able to fund the SPIP through normal means, and Energas failed to demonstrate the financial need to warrant such a rider for its SPIP.

In addition, the SPIP Rider is in essence a cost of service adjustment clause. Commission Rules prohibit cost of service adjustment clauses in the environs of a city, even if approved in the city.[502] It would be inequitable to approve the SPIP Rider in the Cities, but not in the environs. The SPIP Rider should be denied.

Finally, Energas has negotiated away the SPIP Rider in the agreement reached with 59 out of the 67 Cities. Energas also has no such rider for its Amarillo, Dalhart or the Sanford/Fritch Divisions in the Texas panhandle.[503] If the Commission wishes to approve the SPIP Rider, the Examiners recommend that it be approved for all 67 Cities, to provide fair rates for all 67 Cities who will receive the benefit of the replacement and cathodic protection of these mains.

C. SERVICE EXPANSION RIDER (SER)

<u>Contested Issue</u>: Should the Commission approve Energas' proposed Service Expansion Rider (SER)?

<u>Examiners' Recommendation</u>: No. The Examiners recommend denial of Energas' SER.

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498 Energas' Ex. 16 at p. 16.
499 Energas' Ex. 16 at p. 16.
500 Cities' Ex. 5 at p. 13.
501 Energas' Ex. 27 at pp. 1-2.
502 16 TEX. ADMIN. CODE § 7.7(d).
503 Tr. Vol. 5 at pp. 171, 197.

Energas' proposed SER is a charge to new customers of between $7.14 and $11.14 per month for new hook-ups.[504]

1. ENERGAS' POSITION

The SER is designed to recover from ratepayers the incremental cost of investment to initiate new service hook-ups, including the incremental investment, carrying costs, and taxes associated with new residential service connections.[505] The proposed tariff sheets for the SER are attached to Mr. Ives' direct testimony and include proposed tariff sheet 410(a), applicable to all residential customers.[506] In the alternative, if the Commission does not desire for new customers alone to pay the incremental costs to serve them, Energas proposes alternate SER tariff sheet 410(a), which provides for a charge of $0.49 to all residential customers, rather than just the new ones.[507]

The SER is designed to address the historical under-recovery of costs from the residential class.[508] As Mr. Ives describes it, the SER provides a mechanism for "growth to pay for growth."[509] The incremental cost of hooking up a new customer is about $1,100 to $1,200, whereas the cost that is embedded in base rates is about $400. The SER would recover the difference over a 15-year period.[510] Otherwise, attempting to collect the costs all at once would make gas a prohibitively expensive choice.[511]

Further, Energas argues that ratepayers would benefit from the SER because the collected revenues will be credited to plant accounts, reducing the basis for future rate increases: "Although this credit will inure to the benefit of all ratepayers, the SER insures that the costs are paid in the first instance by those who caused them."[512]

Energas further argues that the SER is not piecemeal or single-issue ratemaking. Rather, it is an incremental pricing mechanism, which, as Mr. Ives points out, is preferred by FERC for pipeline expansion projects.[513]

2. CITIES' POSITION

The Cities argue that the SER, like the SPIP Rider, attempts to recover costs incurred in the future that will not be covered in the rates set by the Commission. However, because other costs of Energas will decline after the Commission issues its order, those cost reductions will not

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[504] Energas' Ex. 16 at p. 23.
[505] Energas' Ex. 16 at p. 19, lns. 4-11.
[506] *Id*, attached tariff sheets 410(a).
[507] *Id*., Energas Post-Hearing Brief at p. 113.
[508] *Id.*
[509] *Id at* p. 114.
[510] Tr. Vol. 5 at p. 201, lns. 13-21.
[511] Tr. Vol. 5 at p. 202, lns. 3-8.
[512] Energas' Post-Hearing Brief at p. 114; Energas Ex. 22 at pp. 6-7.
[513] Energas' Ex. 22 at p. 7, lns. 11-14.

be recognized in this rider. Until future cost reductions are recognized, the Cities oppose the SER rider.[514]

In addition, the Cities point out that Atmos has not put the SER rider in place anywhere in the thirteen states it does business, in Amarillo, or anywhere else in Texas. It has been excluded from the NUA between the Company and 59 out of the 67 Cities.[515]

Lastly, the Cities point out that the Texas Utilities Code allows rate base items to be reviewed on an embedded cost basis.[516] Such rate base items should be kept at historic levels as much as possible, because they are reviewed on a historic basis, adjusted for known and measurable changes. The SER rider, on the other hand, provides no incentive to hold down capital costs to a reasonable level.[517] The Cities argue that this amounts to piecemeal ratemaking.

3. EXAMINERS' ANALYSIS

The Examiners recommend denial of Energas' proposed SER. Energas has not provided proof that it requires up-front approval to recover the future costs of hooking up customers. There is no Texas Utilities Code provision that authorizes current rates to be adjusted based on future costs and expenses. Rather, the Cities are correct that rates are set based on a historic test year and actual costs and expenses. The proposed SER, on the other hand, is piecemeal ratemaking to authorize recovery of future costs and expenses. Such historic costs are properly included in Energas' current rate base and amortized. Future costs should not.

Also, as with the SPIP Rider, the SER is in essence a cost of service adjustment clause and cannot be included in environs rates, under Commission Rule 7.7(d). However, it is not equitable for the SER to be approved for the Cities and not the environs.

In addition, Energas has negotiated away the SER in the agreement reached with 59 out of the 67 Cities.[518] Energas also has no such rider for Amarillo.[519] If the Commission wishes to approve the SPIP Rider, the Examiners recommend that it be approved for all 67 Cities, to provide fair rates for all 67 Cities.

D. UTILITY SERVICE CHARGES

Energas' customers are subject to utility service charges for customer specific activities, including meter turn-on (new meter set), turn-on (transfer), turn-on (reconnect), miscellaneous and collection fee, and returned check fee. Revenues derived from these charges are credited to

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[514] Cities' Initial Brief at pp. 135-136.
[515] Tr. Vol. 5 at pp. 170-171; Energas Post-Hearing Brief at p. 113, ftn. 61.
[516] TEX. UTIL. CODE ANN. §§ 104.051-104.054 (Vernon 1998).
[517] Cities' Reply Brief at p. 115.
[518] Energas Ex. 15.
[519] Tr. Vol. 5 at pp. 170-171.

the Company's overall cost of service in the design of base rates.[520] The Company's current and proposed service charges are shown in the table below.[521]

C. Service	a) Energas	
	Proposed	Current
Turn-on (new meter set)	$40.00	$23.50
Turn-on (transfer)	$30.00	$19.00
Turn-on (reconnect)	$40.00	$29.50
Misc. and Collection Fee	$10.00	$10.50
Returned Check	$25.00	$25.00

<u>Contested Issue</u>: Should the Company's proposed service charge increases be adopted?

<u>Examiners' Recommendation</u>: Yes. The Examiners recommend the approval of the Company's proposed service charges (shown above).

1. ENERGAS' POSITION

The Company's witness, Mr. Ives, proposes the service charge increases shown in the above table. He supports the calculation of the proposed service charges with a summary of the average cost of Energas' 1998 utility service work orders[522] and a comparison to the service charges of other Texas utilities.[523] The Company argues that the proposed service charges are based on cost and are reasonable relative to other Texas utilities' service charges.[524]

In response to the Cities' assertion that the Company's work order study does not take into account the reduction in costs resulting from the CSI investment and completion of Oracle, the Company argues in its Reply Brief that the 1998 work order study does reflect lowered costs from new technology investments.[525] In response to the Cities' assertion that the Company's proposed service charges are high relative to those charged by other Texas utilities, the Company notes that its proposed charges are comparable to Lone Star Gas' service charges, which were

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[520] Energas' Ex. 16 at p. 27.
[521] *Id.*, Ex. DMI-8, Sch. 2.
[522] *Id.*, Ex. DMI-8, Sch. 1.
[523] *Id.*, Ex. DMI-8, Sch. 2.
[524] Energas' Reply Brief at p. 95.
[525] Cities' Initial Brief at p. 136. Energas' Reply Brief at p. 95.

effective April 1999.[526] Energas notes that the lower service charges for the other Texas utilities were effective between 1991 and 1993; the charges have not been changed in up to nine years.[527]

2. CITIES' POSITION

In their Initial Brief, the Cities argue that the Company's proposed service charge increases should be rejected. As noted above, the Cities consider the 1998 work order study flawed because it does not include savings from information technology investments. The Cities note that the proposed service charges are "out of line" when compared to other gas utilities.[528] While the Cities reject the proposed service charges, they make no alternative recommendation.

3. EXAMINERS' ANALYSIS

The Examiners recommend approval of the Company's proposed service charges. The Company supports its proposed service charges with a detailed work order study.[529] The Cities wait until their Initial Brief to present their challenge to this study. Given this late objection, the Company does an adequate job of defending its study in its Reply Brief.

The proposed service charges are comparable to the service charges recently adopted by Lone Star Gas, effective in March 1999.[530] Although Energas' proposed service charges are higher than both Southern Union and Entex service charges effective in 1991 and 1993, the Examiners believe that the more recent services charges put into effect by Lone Star Gas in 1999 are more representative of current fees charged by other utilities, and validate the service charges requested by Energas.

Overall, the Company's proposed service charges appear reasonable and should be adopted. According to Mr. Ives' testimony, the Company's proposed service charges result in an increase to Energas' Other Revenue of $458,890.[531] The West Texas System's allocated share of this increase is $325,985, based on the 71.0377% allocation factor for Energas' West Texas Distribution System.[532]

IX. NON-UNANIMOUS SETTLEMENT AGREEMENT

As a result of a Commission-assisted mediation, 59 out of the 67 Cities ratified a Settlement Agreement with rates based upon a revenue requirement increase of $3,010,837, and the same depreciation rates and rate design that Energas proposes in this case. The proposed

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[526] Cities' Initial Brief at p. 136. Energas Reply Brief at p. 95.
[527] Energas' Reply Brief at p. 95.
[528] Cities' Initial Brief at p. 136.
[529] Energas' Ex. 16, Ex. DMI-8, Sch. 2.
[530] *Id.*
[531] Energas Ex. 16, Ex. DMI-8, Sch. 1.
[532] Mr. Ives uses an 82% allocation factor in his Ex. DMI-8, Sch.1, to arrive at a West Texas increase of $376,290, but does not explain its origin. Therefore, the Examiners used the allocation factor of 71.0377% presented in Mr. Cagle's testimony, in Energas Ex. 5 at p. 16, used throughout this PFD.

rates are attached to the Settlement Agreement.[533] These rates were approved as Temporary Rates for the Settling Cities and as Bonded Rates for the environs of all 67 Cities, in Commission Orders signed October 25, 2000. The Examiners have attached the tariffs from these Orders to this PFD, for reference, as Examiners' Attachment A.

The Settlement Agreement contains, in pertinent part, the following provisions:

1. Cities agree to grant Energas an increase in natural gas rates of $3,010,837, to be implemented according to the attached rate design schedules (Exhibit A).

2. Cities and Energas agree that the natural gas rate increase will be effective for natural gas service rendered on and after October 1, 2000.

3. Energas agrees not to increase customer service fees under this Agreement.

4. Energas agrees not to implement new natural gas rates in the West Texas System earlier than three (3) years from the Effective date of the gas rates established by this Agreement. Energas may request suspension of this rate moratorium due to:

a. legislative or regulatory action that has a direct impact on Energas' cost of providing service and results in known and measurable increases in annual non-fuel operating expenses of more than $2.5 million;

b. other unforeseen and unforeseeable events beyond Energas' control that result in known and measurable increases in Energas' annual non-fuel operating expenses in excess of $5 million; or,

c. the effect of tornado, act of war, act of God or other uncontrollable and unforeseeable catastrophic event causing Energas to expend, or to anticipate expending, $5 million or more in response thereto or as a result thereof.

5. Energas agrees not to request changes to its customer service fees in the West Texas System earlier than two (2) years from the effective date of the gas rates established by this Agreement and will not appreciably reduce its level of customer service fees in the West Texas System earlier than two (2) years from the effective date of the gas rates established by this agreement and will not appreciably reduce its level of customer service prior to requesting a change in customer service fees.

6. Energas agrees to adopt depreciation rates as proposed by the Company in Gas utilities Docket (GUD) No. 9002-9135.[534]

This Settlement Agreement was ratified by 49 of the 59 Settling Cities with a "Most-Favored Nations" (MFN) clause that allows the City to choose the lower rate should the Non-Settling Cities obtain a lower rate through this proceeding. Energas extended the MFN clause to the other ten Cities who did not ratify the Settlement Agreement with the MFN clause.[535]

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[533] Energas Ex. 15.
[534] Energas' Ex. 15, Attachment B.
[535] Energas' Ex. 15, Attachment C.

Contested Issue: Should the Non-Unanimous Agreement (NUA) reached between Energas and 59 out of the 67 Cities be approved?

Examiners' Recommendation: No. Energas has not proved that the proposed depreciation rates, rate design, and class cost allocation in the NUA are reasonable. The Examiners recommend approval of the same rates for both the Settling and Non-Settling Cities, using Energas' existing rate design with the increase to its revenue requirement proposed in this PFD, of $4,374,147.

A. ENERGAS' POSITION

Energas argues that the NUA is reasonable because it has proved its need for a revenue increase well in excess of the $3.01 million increase agreed to in the NUA, as well as the reasonableness of the Company's class cost allocation and rate design proposals. Energas requests that the NUA be approved in its entirety for application to the Settling Cities. Furthermore, Energas is willing to accede to and accept the terms of a final order adopting the NUA, in its entirety, for application to the Non-Settling Cities, along with the burden of all rate case expenses incurred since the dates the Settling Cities each ratified the NUA.[536]

Energas further argues that it is immaterial that ten of the 59 Settling Cities ratified the NUA without the Most Favored Nations (MFN) clause. Rather than assuming that the Cities believed that the NUA was a "bad deal" because the MFN clause was added, Energas proposes that, knowing after June 21st that Lubbock would not ratify the NUA, the Cities thought that the MFN clause would provide "political cover" in the event that Lubbock was successful before the Commission.[537]

Next, Energas disagrees with the Cities' proposition that the Commission should not raise rates going into the winter months, when the price of gas has risen as it has. Rather, Energas points to statements by Atmos' Vice-President of Gas Supply, Mr. Gordon Roy, who opines that gas prices could fall in November 2000.[538]

Lastly, Energas argues that the three-year moratorium in the NUA is not a danger if its cost of service falls within the next three years, because a $3.1 million rate increase is not significantly large, and because the Commission could initiate a rate reduction inquiry under Texas Utilities Code § 104.151.[539]

B. CITIES' POSITION

The Cities argue that the level of the increase is excessive, and the rate design makes a major shift in revenue requirement responsibility to low use residential customers and low use

[536] Energas' Post-Hearing Brief at pp. 116-117.
[537] Energas' Reply Brief at p. 97.
[538] Energas' Reply Brief at p. 98; Cities' Ex. 1 at p. 1.
[539] TEX. UTIL. CODE ANN. § 104.151 (Vernon 1998).

commercial customers. Further, the new rates will go into effect at a time when the cost of gas billed to West Texas ratepayers is expected to be 50% higher than the price billed By Energas last winter.[540] Also, the Cities argue that Energas O&M and rate base costs should be driven down over the next three years because of new acquisitions.

Finally, the Cities argue that Energas was having difficulty getting West Texas cities to ratify the NUA without a MFN.[541] Mr. Bryan Easum, City Manager of the City of Tulia, Texas, testified that he told the City Council not to ratify the NUA prior to the time the MFN was agreed to by Energas because it was important.[542] Thus, the Cities argue, the "MFN Cities" are aligned with the non-ratifying cities to the extent that they may benefit from the lower rates or better rate design or better terms resulting from the efforts of the Non-Settling Cities.[543]

C. EXAMINERS' ANALYSIS

The Examiners recommend that the Commission find that Energas failed to meet its burden of proof to show that the NUA is reasonable, and instead set rates based on the proved revenue requirement increase of $4,374,147, with the current rate design in effect, and the Examiners' recommended depreciation rates. Energas argues that it agrees with the NUA revenue increase of $3,010,837 only if the entire Settlement Agreement is approved.[544] Because Energas has not proved that its proposed rate design and depreciation rates are reasonable, the Examiners recommend a finding that Energas did not meet its burden of proof to show that the NUA, as a whole, is reasonable. Instead, the Examiners recommend allowing Energas the higher revenue increase of $4,374,147, using the rate design and class cost allocation currently in place.

Energas must still meet its burden of proof, even though it has settled with 59 Cities. Rather than dismissing its appeals and having the Cities set the agreed rates, Energas has maintained the appeals, asking the Commission to set appropriate rates at the conclusion of this hearing. As long as those dockets are on appeal, Energas must meet its burden of proving that its requested rates are those that the Cities should have set in the ordinances to which the appeals apply.[545]

Furthermore, Energas still has the same burden of proof for all 67 uncontested environs dockets and the 59 Settling Cities dockets whether or not these settled dockets are severed out of this hearing. The hearing provides Energas the opportunity to provide the necessary evidence to prove its proposed rates and rate design. Granted, the contested hearing also allows controverting testimony that would not be present in an uncontested case, but the Commission must still perform an independent review of the supporting documentation and make a judgment on the proposed rates. The Examiner's recommendation to deny Energas' proposed change in its rate design is based on Energas' failure to provide a study that is based on West Texas System

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540 Cities' Initial Brief at pp. 138-139; Energas' Ex. 15, Tab B, Exhibit A at p. 2.
541 Cities' Initial Brief at p. 139; Tr. Vol. 5 at pp. 157-159.
542 Tr. Vol. 8 at pp. 100-101.
543 Cities' Initial Brief at p. 141.
544 Energas' Post-Hearing Brief at pp. 116-117; *Response of Energas Company to Cities' Motion To Require Amendment of Application and Statement of Intent and To File Proposed Tariff Changes*, August 23, 2000.
545 TEX. UTIL. CODE ANN. §§ 103.055(b) & 104.008 (Vernon 1998).

data, rather than Amarillo's. Energas' failure to prove its proposed rate design and depreciation rates is the same, whether it is in an uncontested docket or a contested docket.

Therefore, the Examiners recommend that the Commission reject the rates proposed in the NUA as unsupported by competent evidence, and set the same rates for both the Settling Cities and the Non-Settling Cities, and all West Texas environs. The Commission's order setting rates should not, however, affect the parties' ability to effectuate the Settlement Agreement reached between them if they so choose. The Resolution passed by the City of Odessa City Council, ratifying the Settlement Agreement, contemplates selecting either the rates set by the Commission, or the rates in the Settlement Agreement:

> In the event that the City decides not to select the rates contained in the order of the Railroad Commission for any city which does not ratify this Settlement Agreement, the rates and terms contained in this Settlement Agreement shall continue to be applicable in the City in all respects.[546]

In like manner, the testimony of Mr. Easum, the City of Tulia's City Manager, indicates that the MFN Clause in the Settlement Agreement was an "insurance policy" that assured the Cities' ability to choose their rates:

> The inclusion of a most favored Nation clause removed all the downside to approving the agreement and provided a potential upside. It established a ceiling or limit on the amount of the rate increase Energas is entitled to, but leaves open the possibility that Tulia could benefit from a lesser increase or even a rate decrease either negotiated by another city or ordered by the Railroad Commission.[547]

Thus, the Examiners recommend that the Commission set the rates proposed herein, without giving special deference to the settled rates. Though the Examiners recognize that parties should be encouraged to mediate and settle their differences, the rate design and depreciation rates in the Settlement Agreement in this case are not supported by credible evidence, and Energas has failed to meet its burden of proof on those issues. Therefore, the Commission should set the Examiners' proposed rates.

Given the Examiners' recommendation on the rate design, revenue requirement increase, and depreciation rates, the other terms of the NUA are irrelevant. Likewise, the Examiners find the parties' arguments about whether the Cities would have entered into the NUA without the MFN clause to be irrelevant. The record shows that 49 of the Cities ratified the NUA after July 11, 2000 with the MFN clause, and Energas has offered the MFN clause terms to the remaining ten Cities who ratified the NUA without it.[548] The Commission is not bound by this agreement, and should set rates in accordance with the "cost of service" methodology found in Texas Utilities Code Chapter 104, and as recommended by the Examiners.

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[546] Energas' Ex. 15, Attachment D.
[547] Cities' Ex. 100 at p. 3; *See also*, Cities' Initial Brief at p. 140; Tr. Vol. 8 at pp. 100-101.
[548] Energas' Ex. 15, Attachment C; Tr. Vol. 5 at p. 152.

Nonetheless, if the Commission wishes to consider the other terms of the NUA, such as the two- and three-year moratoriums on rate changes, the Examiners recommend denial of such terms. Energas has not provided justification as to why the Commission should bind its own hands, or Energas' hands, on making needed changes to its rates. Further, a utility has the right under Texas Utilities Code § 104.102 to file a statement of intent to change its rates with the governmental authority having original jurisdiction, whether it is the Cities for rates within the Cities, or the Commission for rates in the environs. If Energas wishes to bargain away this right for three years with the Cities, it does not bind the Commission to enter such agreement into its ratemaking order. Rather, enforcement of those terms of the NUA should be left to Energas and the Cities, who have original jurisdiction over Energas' rates for customers within those Cities.[549]

X. RATE CASE EXPENSES

The Examiners' discussion and recommendation with respect to this issue will be issued by way of a supplement to this Proposal for Decision.

Issued this 2nd day of November, 2000.

Respectfully submitted,

Jim Bateman
Hearings Examiner
Gas Services Section
Office of General Counsel

Mark Evarts
Technical Examiner
Gas Services Division

[549] TEX. UTIL. CODE ANN. § 103.001 (Vernon 1998).

RAILROAD COMMISSION OF TEXAS

STATEMENT OF INTENT FILED BY	**§**	
ENERGAS COMPANY TO INCREASE	**§**	
RATES CHARGED IN THE ENVIRONS	**§**	**GAS UTILITIES DOCKET**
OF 67 WEST TEXAS CITIES;	**§**	**NOS. 9002-9135**
PETITION BY ENERGAS COMPANY	**§**	
FOR REVIEW OF 67 MUNICIPAL	**§**	
RATE DECISIONS	**§**	

PROPOSED FINAL ORDER

Notice of Open Meeting to consider this order was duly posted with the Secretary of State within the time period provided by law, pursuant to Tex. Gov't Code Ann., Chapter 551 et seq. (Vernon 1994 & Supp. 2000).

This matter was duly considered following notice and hearing by hearings examiners who filed a Proposal for Decision containing findings of fact and conclusions of law in accordance with 16 TEX. ADMIN. CODE § 1.141 (West 2000). The Proposal for Decision was properly served on all parties, and all parties were given an opportunity to file exceptions and replies as part of the record as authorized under 16 TEX. ADMIN. CODE § 1.142 (West 2000). The Railroad Commission of Texas, after review and due consideration of the Proposal for Decision, adopts the following findings of fact and conclusions of law and orders as follows:

FINDINGS OF FACT

Procedural History and Notice

1. Energas Company (Energas) is a gas utility serving the sixty-seven (67) West Texas Cities of Abernathy, Amherst, Anton, Big Spring, Bovina, Brownfield, Village of Buffalo Springs, Canyon, Coahoma, Crosbyton, Dimmitt, Earth, Edmonson, Floydada, Forsan, Friona, Hale Center, Happy, Hart, Hereford, Idalou, Kress, Lamesa, Levelland, Littlefield, Lockney, Lorenzo, Los Ybanez, Lubbock, Meadow, Midland, Muleshoe, Nazareth, New Deal, New Home, O'Donnell, Odessa, Olton, Opdyke West, Palisades, Pampa, Panhandle, Petersburg, Plainview, Post, Quitaque, Ralls, Ransom Canyon, Ropesville, Seagraves, Seminole, Shallowater, Silverton, Slaton, Smyer, Springlake, Stanton, Sudan, Tahoka, Tanglewood, Timbercreek, Tulia, Turkey, Vega, Wellman, Wilson, and Wolfforth, Texas, and their environs, which comprise Energas' West Texas System.

2. Energas filed Statements of Intent with all of the 67 Cities on August 4, 1999, and all 67 Cities denied the rate increases.

3. Energas timely filed its *Petition for Review of Municipal Rate Decisions* as to sixty-one cities on March 8, 2000, under Texas Utilities Code Section 103.005 *et seq*. The earliest of the governing bodies of these 61 cities made their final rate decisions on February 7,

2000. Service of this Petition was made on these 61 cities by first-class U.S. mail, postage prepaid, on March 8, 2000.

4. Energas filed a subsequent *Petition for Review of Municipal Rate Decisions and Motion to Consolidate* as to six additional Cities on March 30, 2000, under Texas Utilities Code Section 103.005 *et seq*. The earliest of the governing bodies of these six cities made its final rate decision on March 7, 2000. Service of the Petition on these six cities was made through their attorney of record, and through the representation provided by the West Texas Steering Committee.

5. Energas' *Petitions for Review of Municipal Rate Decisions* of the 67 Cities' municipal rate decisions, filed on March 8, 2000 and March 30, 2000, were docketed as Gas Utilities Docket (GUD) Nos. 9069-9135 (appeals dockets).

6. On March 8, 2000, Energas filed its *Statement of Intent to Change Environs Gas Rates and Motion to Consolidate* as to the environs of the same 67 Cities, under Texas Utilities Code Section 104.102. The Statement of intent was docketed as GUD Nos. 9002-9068 (environs dockets).

7. Prior to its proposed effective date for the environs dockets of April 27, 2000, Energas published notice of its *Statement of Intent to Change Environs Gas Rates and Motion to Consolidate* as to the 67 Cities' environs for four successive weeks in newspapers which collectively have general circulation in each county containing territory affected by the proposed increases, under TEX. UTIL. CODE ANN. §104.103(a)(1) (Vernon 1998).

8. On March 21, 2000, the Commission ordered that the rates proposed in Energas' Statement of Intent be suspended for 150 days from the date the rates would otherwise go into effect.

9. On April 27, 2000, the Docket Services Section of the Office of General Counsel received eighteen pages of signatures indicating protests to Energas' proposed rate increase. The Examiners provided the individuals who protested an opportunity to file petitions to intervene, but none did.

10. On April 5, 2000 the Cities of Plainview, Earth, Odessa, New Home, Nazareth, Big Spring, O'Donnell, Ransom Canyon, Coahoma, Seminole, Panhandle, Tulia, Olton, Smyer, Sudan, Opdyke West, Springlake, Friona, Midland, Silverton, Timbercreek, Pampa, Lockney, Kress, Seagraves, Village of Lake Tanglewood, Idalou, Littlefield, Vega, Ralls, New Deal, Amherst, and Wilson filed a Motion to Intervene. On April 26, 2000, the Cities of Bovina, Brownfield, Crosbyton, Hale Center, Happy, Hart, Lamesa, Muleshoe, Post and Quitaque filed a Motion to Intervene. The Examiners granted these Motions to Intervene from a total of 46 out of the 67 cities named in the appeal, all represented by Jim Boyle, Attorney.

11. Fifty-nine (59) of the Cities (Settling Cities) ratified a Settlement Agreement (Non-Unanimous Settlement Agreement, or NUA) reached with Energas; eight of the Cities did not ratify the Settlement Agreement. The cities that did not ratify the Settlement

Agreement were Big Spring, Brownfield, Hale Center, Lamesa, Levelland, Lubbock, Shallowater, and Wolfforth, Texas (Non-Settling Cities).

12. On August 15, 2000, Mr. Boyle filed a Motion to withdraw as attorney for all of the Settling Cities he represented, and to substitute counsel for the Cities of Odessa and Midland. The Examiners granted the Motion on August 17, 2000, and noted the appearance of Geoffrey Gay, Attorney, for the Cities of Odessa and Midland.

13. The parties agreed to three abatement periods, from May 23 – June 2, 2000; June 8 - August 4, 2000; and October 11 - 24, 2000. Energas filed its written agreement to the abatements and to extend the effective date and statutory deadlines, under TEX. UTIL. CODE ANN. §§ 103.055(c) & 104.107 (Vernon 1998), to December 5, 2000. The Examiners set a procedural schedule that contemplates Commission action by December 5, 2000.

14. The hearing on the merits convened on August 28, 2000 and continued through September 6, 2000.

15. Initial briefs were filed on September 18, 2000. Reply briefs were filed on September 25, 2000.

16. A hearing on rate case expenses was held on October 10, 2000, and briefs on rate case expenses were filed on October 17, 2000.

17. The Commission approved temporary rates for the 59 Settling Cities, and bonded rates for the environs of all 67 Cities, on October 25, 2000.

Revenue Requirement

18. Energas' current revenue requirement of $45,701,207 should be increased by $4,374,147.

Rate Base

19. It is reasonable to allow a total of $115,614,855 as Energas' net original cost rate base.

Allocation of New Technology Investments

20. Energas has properly allocated to its rate base $33,930,993 of Atmos' new information technology investments, based upon approximately 1,025,000 Atmos customers, excluding 48,000 customers on the United Cities Gas Company (UCG) system in Missouri, newly acquired in June 2000, and 279,000 customers on the Louisiana Gas Service (LGS) system, which is currently in the process of being acquired by Atmos.

21. It is reasonable to exclude the 48,000 Missouri customers, acquired in June 2000 on the UCG system, because not all of the attendant impacts are known, such as the corresponding costs to be allocated from Atmos' Customer Service Center.

22. It is reasonable to exclude the 279,000 customers in the Louisiana Gas Service (LGS) system from the allocation calculation because the system has not yet been acquired; therefore, the additional customers have not yet been realized, and it is not a known and measurable change.

23. It is reasonable to exclude Energas' $782.00 portion of disproved Atmos expenses for information technology startup costs.

24. It is not reasonable to exclude from rate base 10% of the information technology costs and order an outside audit of the CSI project costs, as the Cities request.

25. It is reasonable to remove Severance Costs and Outplacement Fees from rate base, thereby reducing the Company's requested rate base by $3,189,002, and associated depreciation expense by $266,905.

26. It is reasonable to exclude from rate base Energas' $128,033 portion of the fee Atmos paid to Micon Consulting, Inc.

Cash Working Capital

27. A total Cash Working Capital of negative $628,223 is reasonable.

28. The Dollar Value of Purchased Gas of $74,537,396 is reasonable.

29. A Revenue Lag of 39.51 days is reasonable.

30. Energas' Payroll Paid Time Off lead days of 45.90 is reasonable.

31. An Other O&M lead days value of 30.98 is reasonable.

32. A Federal Income Tax (FIT) lead days value of 76.14 is reasonable.

33. An 80.00 lead day period for CSC Other Taxes is reasonable.

Rate of Return

34. The appropriate debt and equity ratios to apply to Energas are 41.29% long-term debt, 10.24% short-term debt, and 48.17% common equity.

35. Energas' cost of long-term debt is 8.06%, and its cost of short-term debt is 6.35%.

36. Energas has substituted short-term debt for preferred stock for purposes of determining a capital structure and cost of capital in this rate Order.

37. A cost of equity of 12.20% is reasonable and based on the updated results from constant growth discounted cash flow (DCF) analyses, non-constant DCF analyses, and CAPM, or

risk premium, analyses, using Atmos and a proxy group of six local distribution companies (LDCs).

38. An overall rate of return of 9.87% is reasonable.

Revenues

39. Energas' appropriate normalized test year revenue at present rates is $45,701,207.

Weather Normalization

40. Energas weather-normalized city gate test year volumes in a manner consistent with the Railroad Commission of Texas' *Natural Gas Rate Review Handbook.*

41. Energas' proposed weather normalization adjustment of 2,668,208 Mcf is reasonable and appropriate. This increases the test year revenue by approximately $2,632,196.

Customer Growth Normalization

42. Energas' customer growth adjustment to increase volumes by 32,849 Mcf is reasonable and necessary.

43. Energas' 32,849 Mcf customer growth adjustment results in a $138,840 increase to test year revenue.

Lubbock Power and Light Transportation Revenue

44. Energas reasonably excluded $120,000 in revenues received for transportation on the Lubbock Power and Light Transportation Line from its normalized test year revenue.

Rental Income

45. Energas reasonably included $77,615 in revenues from the additional rents received from subleased office space in its normalized test year revenue.

Expenses

Depreciation

46. The appropriate annual depreciation expense in this case is $4,857,698. This amount is reasonable and is adopted.

47. Energas' annual depreciation expense included in its cost of service was $7,895,888. This amount is unreasonable and should not be adopted.

48. When Energas' proposed depreciation expense of $7,895,888 is adjusted to include the service lives and survivor curves in the Findings of Fact below, is re-calculated using the ALG calculation method, and is adjusted to exclude depreciation expense from excluded severance costs in rate base, adjusted depreciation expense is $4,857,698.

ELG vs. ALG

49. The Equal Life Group (ELG) depreciation calculation method proposed by Energas is unreasonable in this case and should not be used.

50. ELG is inappropriate in this case due to Energas' limited historical data and lack of detailed information about the assets underlying the life estimation process.

51. ELG is inappropriate in this case because it magnifies the error associated with natural inaccuracies between forecasts and actual future events, is time sensitive compared to ALG calculated rates, produces rates that are outdated by the time of implementation, and requires constant rate changes if it is to be applied properly.

52. ELG is rarely utilized by energy companies and their regulators.

53. The ELG calculation method has a greater impact on rates when there is substantial new investment.

54. Energas has made substantial new investments in information technology during and since the test year.

55. It is reasonable to retain the Average Life Group (ALG) depreciation calculation method currently in place for Energas' West Texas Distribution System.

56. The ALG calculation method is a straight-line method that is preferable to the Equal Life Group (ELG) depreciation calculation method in this case, and should be used.

Service Lives and Survivor Curves

57. A 75-year service life and an R1.5 curve for Energas' Account 367, Distribution Plant, Mains, are reasonable and are adopted.

58. A 15-year service life and an SQ survivor curve for Energas' Account 390.09, Leasehold Improvements, are reasonable and are adopted.

59. An 8-year service life and an SQ survivor curve for Energas' Account 399.86, General Plant, PC Hardware, Divisions 2, 5, 10, & 21, are reasonable and are adopted.

60. A 10-year service life and an SQ survivor curve for Energas' Account 399.88, Application Software, Divisions 2, 5, 10, & 21, are reasonable and are adopted.

61. A 10-year service life and an SQ survivor curve for Energas' Account 399.99, OS Software, Division 2, are reasonable and are adopted.

Net Salvage

62. Energas has properly excluded third party reimbursements that are applicable to the cost of replacement from the calculation of net salvage.

63. Energas' proposed net salvage level of negative 15% for Account 376, Distribution Mains, is reasonable.

64. A net salvage level of negative 15% for Account 378, All Other Distribution Plant, is reasonable; Energas' requested negative 25% net salvage level for this account is not reasonable.

Fully Depreciated Accounts

65. Energas treatment of fully depreciated accounts is appropriate and reasonable. Energas has properly set the depreciation rate to zero for fully depreciated accounts.

Severance Cost Depreciation Expense

66. It is reasonable to exclude Severance Costs from depreciable rate base, which decreases depreciation expense by $266,905.

Other Post-Employment Benefits (SFAS 106)

67. An expense of $882,188 is reasonable for Energas' Other Post-Employment Benefits (OPEBs), or SFAS-106.

Pensions

68. It is reasonable to allow Energas to set its Pensions fund expense at zero in determining its revenue requirement for ratemaking purposes.

69. It is reasonable to require Energas to continue accrual accounting for this account to track its level for future ratemaking.

Payroll Expenses

70. It is reasonable to disallow Energas' claimed $133,545 Unfilled Positions Expense because it is not known and measurable.

71. Energas' $200,728 increase to updated Payroll Expense through February 2000 is reasonable because it is known and measurable.

72. It is reasonable to exclude an adjustment for Merit Increases.

73. It is reasonable to disallow Energas' proposed Bonus / Incentive Compensation expense of $443,238 because it is not known and measurable.

74. Energas' overtime expense of $692,385 is reasonable because it is known and measurable as included in updated Payroll Expense through February 2000.

75. It is reasonable to decrease Energas' test year expense for Other Employee Benefits by $388,801, to reflect the Company's calculation of these expenses through February 2000, because it is a known and measurable change.

<u>Allocated Energas General Office Expenses, Allocated Shared Services, including Mr. Best's Compensation Expenses</u>

76. Energas' allocation factors for Energas General Office expense and Atmos Shared Services expense are reasonable.

77. Energas properly allocates 25.76% of Mr. Bests' test year compensation of $2,256,129 to Energas.

<u>Leased Vehicles Expense</u>

78. It is reasonable to disallow $904,781 of Energas' proposed depreciation expense for owned vehicles.

79. It is reasonable to increase the leased vehicles expense $167,416 from test year levels.

<u>Meter Reading Expense</u>

80. It is reasonable to approve a meter reading expense of $789,351, which is a decrease of $110,562 from Energas' proposed expense of $899,913.

<u>Uncollectible Expense</u>

81. Energas' Uncollectible Expense of $1,261,765 is reasonable.

<u>Private Airline Expense</u>

82. It is reasonable to disallow Energas' $13,411 Private Airline Expense.

<u>Customer Support Center Expense</u>

83. It is reasonable to approve a $732,558 increase to Energas' test year Customer Support Center Expense as a known and measurable change.

84. Energas' Customer Support Center Expense of $2,117,725 is reasonable.

Taxes

85. A Federal Income Tax expense of $3,658,511 is reasonable.

86. An expense of $4,149,681 for Taxes Other than Income Taxes is reasonable.

Customer Growth Expense

87. It is reasonable to disallow Energas' proposed adjustment of $9,337 to O&M as a Customer Growth Expense, because it is not a known and measurable change.

Merger Expenses

88. Energas' test year Merger Expenses should not be reduced by $405,280.

Factoring

89. Energas' O&M expense should not be reduced by $423,289 for its failure to factor its accounts receivable.

Class Cost Allocation

90. It is reasonable to allocate costs to Energas' various customer classes based on Energas' existing rate structure.

91. Energas proposed a class cost allocation based on a Class Cost Service Study (CCOS) that was developed using proxy data from Energas' Amarillo system.

92. Energas failed to meet its burden to prove that it is reasonable to base its class cost allocation for its West Texas System using the CCOS study that was developed with Amarillo proxy data.

Rate Design

93. It is reasonable to set rates based on Energas' current rate design, because Energas' proposed rate design is based on the unusable CCOS study.

94. Energas' current rate design is reasonable.

95. It is reasonable to allow Energas to remove gas costs from the base rates.

Steel Pipe Improvement Program Rider

96. Energas did not meet its burden to prove that its proposed Steel Pipe Improvement Program Rider should be approved.

Service Expansion Rider

97. Energas did not meet its burden to prove that its proposed Service Expansion Rider should be approved.

Utility Service Charges

98. Energas has met its burden to prove that its proposed utility service charges are reasonable.

Non-Unanimous Settlement Agreement

99. Energas reached a Settlement Agreement with 59 out of the 67 Cities in this case (Non-Unanimous Settlement Agreement or NUA).

100. The Non-Unanimous Settlement Agreement reached between Energas and 59 Cities should not be approved for those Cities, because Energas failed to meet its burden to prove that the Rate Design, Class Cost Allocation, and Depreciation rates in the Settlement Agreement are reasonable.

Rate Case Expenses

101. The Non-Settling Cities' rate case expenses in the amount of $454,561.31 are reasonable and should be reimbursed by Energas to the eight Non-Settling Cities within thirty days of the date of this Order.

102. The Non-Settling Cities' estimated rate case expenses for completion of this rate case before the Commission and for appeals, in the amount of $285,000, are reasonable, and should be reimbursed by Energas to the eight Non-Settling Cities within thirty days of receipt of invoices documenting such expenses.

103. It is reasonable to allow for estimated rate case expenses for completion of this rate case before the Commission, and for appeals.

104. Energas' rate case expenses in the amount of $1,233,191.51 for work through September 2000 are reasonable.

105. Energas did not meet its burden to prove that its requested rate case expenses in the amount of $1,437,137.87 are reasonable.

106. Energas' estimated rate case expenses for completion of this rate case before the Commission and for appeals, in the amount of $490,000, are reasonable.

107. Energas' rate case expenses should be allocated equally among all of its customers in the 67 Cities and their environs.

108. Energas should be allowed to recover its rate case expenses through a volumetric surcharge on all customer bills, calculated on a per CCF basis over a three year period, with interest at 6.00% on the unreimbursed balance.

109. Energas should be allowed to revise its surcharge recovery factor quarterly for additional incurred expenses that are consistent with the Commission-approved $490,000 in estimated expenses for work performed after September 2000.

CONCLUSIONS OF LAW

1. Energas is a gas utility as defined in the Texas Utilities Code (TUC), at TEX. UTIL. CODE ANN. §§ 101.003(7) and 121.001 (Vernon Supp. 2000).

2. Energas is subject to the jurisdiction of the Railroad Commission of Texas, under TEX. UTIL. CODE ANN. § 102.001, 103.051, 104.001, & 121.151 (Vernon 1998).

3. Energas' filing and publication of notice of its *Statement of Intent to Change Environs Gas Rates and Motion to Consolidate* comply with the requirements of TEX. UTIL. CODE ANN. §§ 104.102 & 104.103 (Vernon 1998).

4. Energas' filing and public notice of its *Petitions for Review of Municipal Rate Decisions* comply with the requirements of TEX. UTIL. CODE ANN. § 103.054 (Vernon 1998).

5. Energas' rate base includes the adjusted value of invested capital used and useful to the utility in providing service, as required by TEX. UTIL. CODE ANN. § 104.053(a) (Vernon 1998).

6. The overall revenue requirement established in this Order will permit Energas a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses, under TEX. UTIL. CODE ANN. § 104.051 (Vernon 1998).

7. The rates established in this Order will not yield more than a fair return on the adjusted value of the invested capital used and useful in providing service to the public, under TEX. UTIL. CODE ANN. § 104.052 (Vernon 1998).

8. Energas' overall revenues, as established in this order are at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.

9. The Commission is required to establish proper and adequate rates and methods of depreciation for each class of property of a gas utility, under TEX. UTIL. CODE ANN. § 104.054(a) (Vernon 1998).

10. Book depreciation and amortization for ratemaking purposes must be computed on a straight-line basis over the useful life expectancy of the item of property or facility in question, under 16 TEX. ADMIN. CODE § 7.51(a) (West 2000).

11. Energas failed to meet its burden of proof on the elements of its requested rate change as identified in this order. TEX. UTIL. CODE ANN. § 104.008 (Vernon 1998).

12. The rates and rate design reflected in the findings of fact and Schedules are just and reasonable, not unreasonably preferential, prejudicial, or discriminatory, but are sufficient, equitable, and consistent in application to each class of consumers, under TEX. UTIL. CODE ANN. § 104.003 (Vernon 1998).

13. Each party seeking reimbursement for its rate case expenses has the burden to prove the reasonableness of such rate case expenses by a preponderance of the evidence, under 16 Tex. Admin. Code § 7.57 (West 2000).

14. The rate case expenses enumerated in the findings of fact herein are reasonable and comply with 16 Tex. Admin. Code § 7.57 (West 2000).

15. The Commission ahs the authority to allow Energas to recover rate case expenses through a surcharge on its rates, under TEX. UTIL. CODE ANN. § 104.051 (Vernon 1998).

16. It is reasonable for the Commission to order Energas to pay the Non-Settling Cities' incurred rate case expenses within 30 days of this Order, and estimated rate case expenses within 30 days of receipt of invoices, under TEX. UTIL. CODE ANN. § 103.022 (Vernon 1998).

IT IS THEREFORE ORDERED that Energas' requested rates are **DENIED**

IT IS FURTHER ORDERED that the rates and rate design reflected in the findings of fact and conclusions of law and in the Schedules are **APPROVED**.

IT IS FURTHER ORDERED that Energas shall file tariffs incorporating rates consistent with this Order within thirty days of the date of this Order.

IT IS FURTHER ORDERED that Energas is authorized to recover a surcharge on its rates charged to ratepayers in the 67 Cities and their environs, over three years, to recover Energas' rate case expenses through September 2000 as approved herein and the approved rate case expenses that Energas is required to pay to the Non-Settling Cities as set out in the findings of fact herein. Energas shall calculate the surcharge on a per CCF basis over a three-year period, with interest at 6.00% on the unreimbursed balance. Energas may revise the recovery factor quarterly for additional incurred expenses that are consistent with the Commission-approved

$490,000 in estimated expenses for work performed after September 2000. At the end of the three-year period, Energas may true-up the amounts actually recovered with the rate case expenses authorized herein.

IT IS FURTHER ORDERED that Energas shall reimburse the Non-Settling Cities their incurred rate case expenses as approved herein within 30 days after the date of this Order, and estimated rate case expenses within 30 days of receipt of invoices showing actual expenses, up to the amount authorized herein.

IT IS FURTHER ORDERED that this order shall not be final and effective until twenty days after a party is notified of the Commission's order. Under TEX. GOV'T CODE § 2001.142(c), as party shall be presumed to have been notified of the Commission's order three days after the date on which the notice is actually mailed. If a timely motion for rehearing is filed by any party at interest, this order shall not become final and effective until such motion is overruled or, if granted, this order shall be subject to further action by the Commission.

IT IS FURTHER ORDERED that the proposed findings of fact and conclusions of law not specifically adopted herein are **DENIED.** **IT IS ALSO ORDERED** that each exception to the Examiner's Proposal for Decision not expressly granted herein is overruled and all pending motions and requests for relief not previously granted herein are hereby denied.

Signed this ___ day of ____________, 2000.

RAILROAD COMMISSION OF TEXAS

____
MICHAEL L. WILLIAMS
CHAIRMAN

____
TONY GARZA
COMMISISONER

____
CHARLES R. MATTHEWS
COMMISSIONER

ATTEST:

____
SECRETARY

Railroad Commission of Texas
Gas Services Division

Application of Energas Company
GUD Docket Nos. 9002-9135
West Texas Distribution System

Table of Contents for Examiners' Schedules

Energas Company
West Texas Distribution System

Examiners' Recommended Cost of Service

	Description	Energas' Request	Cities' Recommendation	Examiners' Recommendation	Sch.
1	Cost of Gas	-	-	-	
2	Operation & Maintenance Expense	$27,432,833	$20,168,921	$25,709,320	B
3	Depreciation and Amortization Expense	7,895,888	3,346,858	4,857,698	C
4	Taxes Other Than Income Taxes	4,210,132	4,009,629	4,149,681	D
5	Return	11,980,775	9,172,240	11,411,186	E
6	Federal Income Tax	3,876,664	2,837,650	3,658,511	F
7	Interest on Customer Deposits	70,381	70,381	70,381	
8	**Total Cost of Service**	55,466,673	39,605,679	49,856,777	
9	Revenue at Present Rates	45,701,207	45,856,053	45,701,207	G
10	**Net Revenue Deficiency - Recommended**	**$9,765,466**	**($6,250,374)**	**$4,155,570**	
11	Applicable Revenue Tax	513,647	(328,759)	218,576	
12	**Total Revenue Increase (Decrease) - Recommended**	**$10,279,113**	**($6,579,133)**	**$4,374,147**	
13	Percentage Increase (Decrease)	22.49%	(14.35%)	9.57%	

Energas Company
West Texas Distribution System

Examiners' Recommended Operation and Maintenance Expenses

	Description	Energas' Request	Cities' Recommendation	Examiners' Recommendation
	O&M Expense Unadjusted:			
1	Storage & Transmission Expense	$1,194		
2	Distribution Operation	7,751,585		
3	Distribution Maintenance	611,283		
4	Customer Accounts Expense	2,957,593		
5	Customer Service Expense	627,433		
6	Sales Promotion Expense	156,891		
7	Administrative & General Expense	13,481,208		
8	**Total O&M Expense, Unadjusted**	$25,587,187	$25,587,187	$25,587,187
	Proposed Adjustments to O&M Expense:			
	FAS 106 Other Post Employment Benefits:			
9	Change in Number of Employees	-	(98,941)	-
10	Health Care Cost Trend	-	(273,513)	-
11	Discount Rate	-	(86,000)	(86,000)
12	Transition Obligation	-	(76,114)	-
13	External Fund	-	(433,620)	-
14	Total FAS 106 Adjustments - Recommended	-	(968,188)	(86,000)
	Pension:			
15	Updated Pension Report	-	(610,163)	-
16	Reduction of Employees	-	(153,013)	-
17	Pension Expense	1,102,111	-	1,102,111
18	Total Pension Adjustments - Recommended	1,102,111	(763,176)	1,102,111
	Payroll / Other Benefits:			
19	Unfilled Positions	133,545	-	-
20	Updated Payroll	38,517	(377,798)	38,517
21	Merit Increase	-	(171,610)	-
22	Bonus / Incentive Compensation	-	(443,258)	(443,258)
23	Overtime Expense	-	(164,153)	-
24	Updated Other Employee Benefits	(395,996)	(469,125)	(395,996)
25	Total Payroll / Other Benefits Adj. - Recommended	(223,934)	(1,625,944)	(800,737)
	Administrative Expense Transferred (Allocated):			
26	Allocation Factor Change - Atmos Expense	-	(230,998)	-
27	Allocation Factor Change - Energas Expense	-	14,874	-
28	CEO Salary	-	(232,057)	-
29	Total Allocated Administrative Expense - Recommended	-	(448,181)	-
	Other O&M Expense Adjustments:			
30	Leased Vehicles Expense	167,416	167,416	167,416
31	Owned Vehicles Depreciation Expense	(84,086)	(904,781)	(904,781)
32	Meter Reading Expense	-	(251,658)	(110,562)
33	Uncollectible Accounts Expense	-	(422,699)	-
34	Private Airline Expense	(13,411)	(13,411)	(13,411)
35	Customer Support Center Expense	852,674	605,486	732,558
36	Customer Growth Expense	9,337	-	-
37	Merger Expense	-	(405,280)	-
38	Factoring	-	(423,389)	-
39	Customer Billing Group	96,248	96,248	96,248
40	Club Dues	(22,541)	(22,541)	(22,541)
41	Undisputed Adjustment	(38,168)	(38,168)	(38,168)
42	Total Other O&M Expense Adjustments - Recommended	967,469	(1,612,777)	(93,241)
43	**Total Adjustments to O&M**	1,845,646	(5,418,266)	122,133
44	**Total O&M Expense, Adjusted**	**$27,432,833**	**$20,168,921**	**$25,709,320**

Energas Company
West Texas Distribution System

Examiners' Recommended Depreciation Expense

Examiners' Recommendation:

	Description (a)		Amount (b)	Sch.
1	Actual Depreciation and Amortization Expense	$	4,151,737	C-1
2	Adjustment to Reflect Fiscal Year End Level of Plant and Current Depreciation rates		215,447	C-1
3	Adjustment to Reflect Updated Level of Plant		490,514	
4	**Total Depreciation and Amortization Expense, As Adjusted**	**$**	**4,857,698**	

Company's Request:

5	**Total Depreciation and Amortization Expense, As Adjusted**	**$**	**7,895,888**

Cities' Recommendation:

6	**Total Depreciation and Amortization Expense, As Adjusted**	**$**	**3,346,858**

Energas Company
West Texas Distribution System

Examiners' Recommended Depreciation Expense

West Texas System

Line No.	Description	Balance As of 4/30/99	Fully & Non-Deprec Plant	Depreciable Plant	ALG Depr. Rate	Proforma Depreciation	Clearing	Expensed
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Mult. Land	$58,959	$58,959	$0		$0		0
2	374 Land Rights	80,776		80,776	0.26%	210		210
3	302 Plant Accounts - Intangible	4,263	4,263	0		0		0
4	Mult. Plant Accounts - Distrib.	64,534,976		64,534,976	2.74%	1,768,258		1,768,258
5	376 Plant Accounts - Mains	94,970,819		94,970,819	1.29%	1,225,124		1,225,124
6	391 Office Furniture & Equipment	1,494,442		1,494,442	0.22%	3,288		3,288
7	392 Transportation Equipment	7,152,102		7,152,102	20.00%	1,430,420	1,430,420	0
8	393 Stores Equipment	147,858		147,858	4.88%	7,215		7,215
9	394 Tools & Work Equipment - General	3,981,159	8,448	3,972,711	4.88%	193,868		193,868
10	396 Power Operated Equipment	1,533,977	1,533,977	0	10.00%	0		0
11	397 Radio Equipment - Mobile	628,464		628,464	0.75%	4,713		4,713
12	397 Radio Equipment - Fixed	165,093		165,093	0.56%	925		925
13	398 Miscellaneous Equipment	124,226	124,226	0		0		0
14	399 Other Tangible Property - MF HW	426,543	426,543	0	20.00%	0		0
15	399 Other Tangible Property - PC HW	2,422,811		2,422,811	6.58%	159,421		159,421
16	399 Other Tangible Property - PC SW	207,039		207,039	14.56%	30,145		30,145
17	399 Other Tangible Property - Appl. SW	381,511		381,511	10.00%	38,151		38,151
18	399 Other Tangible Property	86,213		86,213	14.29%	12,320		12,320
19	399 Other Tangible Property- Serv-SW	140,987		140,987	14.29%	20,147		20,147
20	391 Office Machines	224,959	224,959	0	10.00%	0		0
21	397 Communication Equipment - Telephone	364,430		364,430	2.22%	8,090		8,090
22	397 Communication Equipment - Telemeteri	81,172		81,172	9.12%	7,403		7,403
23	390 Structures - Frame	3,951	3,951	0	3.00%	0		0
24	390 General Buildings - Brick	4,017		4,017	2.00%	80		80
25	390 Air Conditioning Equipment	28,488	28,488	0	7.00%	0		0
26	390 Improvements to Leased Premises	1,847,227		1,847,227	4.44%	82,017		82,017
27	Total	$181,096,462	$2,413,814	$178,682,648		$4,991,795	$1,430,420	**$3,561,375**
28	Proforma Depreciation Expense							**$3,561,375**
29	Actual Depreciation Expense							**$4,151,737**
30	Proforma Increase (Decrease) (Line 28 minus Line 29)							**($590,362)**
31	Allocated from Atmos General Office (Sch. C-3)							**($711,399)**
32	Allocated from Energas General Office (Sch. C-2)							**$1,517,208**
33	**Total Adjustment to Reflect Year End Plant and Depreciation Rates**							**$215,447**

Energas Company
West Texas Distribution System

Examiners' Recommended Depreciation Expense

Energas General Office

Line No.		Description	Balance As of 4/30/99	Non-Deprec Plant	Depreciable Plant	ALG Depr. Rate	Proforma Depreciation	Clearing	Expensed
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	397	Telemetry	$1,968		$1,968	11.30%	$222		222
2	397	Radio Equipment - Mobile	5,959		5,959	4.19%	250		250
3	391	Office Furniture & Equipment	2,087,532		2,087,532	2.30%	48,013		48,013
4	392	Transportation Equipment	668,467	106,919	561,549	20.00%	112,310	112,310	0
5	394	Tools & Work Equipment	72,140		72,140	6.07%	4,379		4,379
6	398	Miscellaneous Equipment	43,076		43,076	7.00%	3,015		3,015
7	399	Other Tangible Property - Servers H/W	2,028,140		2,028,140	14.29%	289,821		289,821
8	399	Other Tangible Property - Servers S/W	1,685,406		1,685,406	14.29%	240,844		240,844
9	399	Other Tangible Property - Network H/W	650,009		650,009	14.29%	92,886		92,886
10	399	Other Tangible Property - Gen. Startup Cost	3,876,757		3,876,757	8.33%	322,934		322,934
11	399	Other Tangible Property MF Hdwr	5,505		5,505	1.85%	102		102
12	399	P.C. Hardware	1,626,944		1,626,944	10.24%	166,599		166,599
13	399	P.C. Software	274,182		274,182	18.08%	49,572		49,572
14	399	Application Software	9,298,068		9,298,068	10.00%	929,807		929,807
15	391	Office Machines	96,919	96,919	0	5.74%	0		0
16	397	Communication Equipment - Telephone	1,954,958		1,954,958	7.53%	147,208		147,208
17	390	Improvements to Leased Premises	863,874		863,874	6.44%	55,633		55,633
18		Total	$25,239,902	$203,838	$25,036,064		$2,463,595	$112,310	**$2,351,285**
19		Proforma Depreciation Expense							**$2,351,285**
20		Actual Depreciation Expense							**$215,506**
21		Proforma Increase (Line 20 Minus Line 21)							**$2,135,779**
22		**West Texas Distribution System Allocation [1]**							**$1,517,208**

[1] 71.0377% of Energas General Office is allocated to West Texas.

Energas Company
West Texas Distribution System

Examiners' Recommended Depreciation Expense

Atmos General Office

Line No.		Description	Balance As of 4/30/99	Fully & Non-Deprec Plant	Depreciable Plant	ALG Depr. Rate	Proforma Depreciation	Clearing	Expensed
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	391	Office Furniture & Equipment	$3,579,613		$3,579,613	3.53%	$126,360		$126,360
2	392	Transportation Equipment	37,682	18,797	18,885	28.63%	5,407		5,407
3	394	Tools & Work Equipment	33,042		33,042	10.00%	3,304		3,304
4	393	Stores Equipment	6,063		6,063	10.00%	606		606
5	398	Miscellaneous Equipment	662,671		662,671	4.47%	29,621		29,621
6	399	Other Tangible Property	8,144		8,144	23.62%	1,924		1,924
7	399	Other Tangible Property - MF HW	1,171,886		1,171,886	15.82%	185,392		185,392
8	399	Other Tangible Property - PC HW	3,930,228		3,930,228	8.07%	317,169		317,169
9	399	Other Tangible Property - PC SW	1,091,589		1,091,589	17.95%	195,940		195,940
10	399	Other Tangible Property - Appl. SW	18,340,581		18,340,581	7.78%	1,426,897		1,426,897
11	399	Other Tangible Property - MF CPU	1,095,465		1,095,465	24.83%	272,004		272,004
12	399	Other Tangible Property - System SW	3,221,609		3,221,609	6.20%	199,740		199,740
13	391	Office Machines	1,140,200		1,140,200	1.55%	17,673		17,673
14	397	Communication Equipment - Telephone	809,454		809,454	6.17%	49,943		49,943
15	390	Improvements to Leased Premises	6,035,006		6,035,006	4.32%	260,712		260,712
16		Total	$41,163,233	$18,797	$41,144,436		$3,092,692	0	**$3,092,692**
17		Actual Depreciation Expense							**$7,143,825**
18		Proforma Increase (Line 16 Minus Line 17)							**($4,051,133)**
19		**West Texas Allocation [1]**							**($711,399)**

[1] 17.5605% of Atmos General Office is allocated to West Texas.

Energas Company
West Texas Distribution System

Examiners' Recommended Taxes Other than Federal Income Tax

	Description	Energas' Request	Cities' Recommendation	Examiners' Recommendation
1	Ad Valorem	$1,555,078		
2	FICA	491,140		
3	Federal Unemployment	10,098		
4	State Unemployment	36,297		
5	City Franchise	2,539,284		
7	State Transportation	7,535		
8	State Gross Receipts	1,391,115		
9	DOT Transmission	0		
10	**Total Per Books**	6,030,547	6,030,547	6,030,547
	Adjustments:			
11	Corporate Franchise Taxes	501,830	368,243	473,782
12	Revenue Taxes	(2,331,911)	(2,324,174)	(2,331,911)
13	Payroll Related Taxes	9,666	(64,987)	(22,737)
14	**Total Adjustments**	(1,820,415)	(2,020,918)	(1,880,866)
15	**Total Taxes Other Than Income Taxes, Adjusted**	**4,210,132**	**4,009,629**	**4,149,681**
16	Deficiency Related Revenue Taxes (Schedule A)	513,647	(328,759)	218,576
17	Total (including amount calculated on Schedule A)	$4,723,779	$3,680,870	$4,368,257

West Texas Distribution System
Corporate Franchise Tax Adjustment
Twelve Months Ended April 30, 1999

Company:

Line No.	Description (a)	Corporate Amount (b)	West Texas City Plant Portion (c)	Tax Rate (d)	Corporate Franchise Tax (e)
1	Contingent Liabilities	$4,206,491	$738,681		
2	Deferred Taxes	79,469,776	13,087,426		
3	Equity	399,145,929	70,092,021		
4					
5	Texas Franchise Tax Equity	$482,822,196	$83,918,128	0.25%	
6					
7	Texas Franchise Tax Based on Equity				$209,795
8					
9	Officer & Director Compensation [1]	11,667,414	2,048,856	4.50%	92,199
10					
11	Required Net Income After Tax		7,199,525		
12	Federal Income Tax Rate			35.00%	
13	Texas Franchise Tax Rate on Income			4.50%	
14					
15	Combined Tax Rate			37.93%	
16					
17	Required Net Income Before Tax		11,076,189	4.50%	498,428
18					
19	Subtotal				590,627
20					
21	Less: Texas Franchise Tax on Equity				(209,795)
22					
23	Texas Franchise Tax Based on Income				380,832
24					
25	Total Texas Franchise Tax				590,627
26					
27	Texas Franchise Tax per Books in Test Year				88,797
28					
29	Adjustment				501,830
30					
31	[1] Per most recent filing.				

Energas Company
West Texas Distribution System

Examiners' Recommended Rate Base and Return

	Description	Energas' Request	Cities' Recommendation	Examiners' Recommendation	Sch.
		(a)	(b)	(c)	
1	**Gross Plant in Service - Proposed**	$209,458,913	$209,458,913	$209,458,913	
	Recommended Adjustments:				
2	Micon Costs		(128,033)	(128,033)	
3	Severence Costs		(3,189,002)	(3,189,002)	
4	Retainage for Audit		(2,505,295)	(782)	
5	**Gross Plant in Service - Recommended**		203,636,583	206,141,096	
6	**Accumulated Depreciation - Proposed**	(77,616,485)	(77,616,485)	(77,616,485)	
	Recommended Adjustments:				
7	(associated with plant removal lines 2-3 above)		117,353	(1)	
8	**Accumulated Depreciation - Recommended**		(77,499,132)	(77,616,486)	
9	**Net Original Cost of Plant per Books**	**131,842,428**	**126,137,451**	**128,524,610**	
10	Changes to Net Plant through Sep 1999	5,880,261	5,880,261	5,880,261	
11	Accumulated Deferred Federal Income Tax (FIT)	(13,087,426)	(13,087,426)	(13,087,426)	
12	Changes to Deferred FIT through Sep 1999	(5,304,667)	(5,304,667)	(5,304,667)	
13	Customer Advances for Construction	(351,216)	(351,216)	(351,216)	
14	Customer Deposits	(1,357,854)	(1,357,854)	(1,357,854)	
15	Investment Tax Credits	(441,351)	(441,351)	(441,351)	
	Working Capital:				
16	Prepayments	332,409	572,468	332,409	
17	Materials & Supplies	2,048,313	2,048,313	2,048,313	
18	**Cash Working Capital**	7,719	(1,076,521)	(628,223)	E-1
19	**Total Rate Base**	**119,568,615**	**113,019,457**	**115,614,855**	
	Recommended Adjustments:				
20	Re-Allocation of CIS Costs		(13,019,983)	-	
21	Fully Depreciated Account Over-Accruals		(2,318,533)	-	
22	**Total Rate Base - Recommended**	**$119,568,615**	**$97,680,941**	**$115,614,855**	
23	**Rate of Return**	10.02%	9.39%	9.87%	E-2
24	**Return on Rate Base**	**$11,980,775**	**$9,172,240**	**$11,411,186**	

(1) The Examiners were unable to determine from evidence: a) the decrease to Accumulated Depreciation associated with their recommendation to remove Severence Costs and Micon Costs from Rate Base; and b) the decrease to depreciation expense associated with the removal of Micon Costs from rate base.

Energas Company
West Texas Distribution System

Examiners' Recommended Cash Working Capital

Line No.	Description	A Expenses Based on Examiners' Recommendation	B Average Daily Amount (A / 365)	C Revenue Lag Days	D Payment Lead Days	E Check Float Days	F Net Lead/Lag Days (C - D - E)	G Examiners' Recommendation (B * F)
	Operation and Maintenance:							
1	Purchased Gas Cost	74,537,396	204,212	39.51	40.21	0.00	(0.70)	(142,948)
2	Payroll Regular	8,276,802	22,676	39.51	14.00	0.80	24.71	560,324
3	Payroll PTO	842,325	2,308	39.51	45.90	0.80	(7.19)	(16,595)
4	ESOP	502,047	1,375	39.51	14.00	0.80	24.71	33,976
5	Other O&M	18,296,787	50,128	39.51	30.98	7.76	0.77	38,599
6	Federal Income Taxes:	3,707,712	10,158	39.51	76.14	0.00	(36.63)	(372,092)
7	Taxes Other than FIT:	6,576,011	18,016	39.51	80.00	[1]	(40.49)	(729,487)
11	**TOTAL CASH WORKING CAPITAL**							**(628,223)**

Notes:
[1] Check Float Days incorporated in Payment Lead Days for Other Taxes.

Energas Company
West Texas Distribution System

Examiners' Recommended Rate of Return

Examiners' Recommendation:

	Description	Rate Base	Capital Structure	Rate Base by Source of Capital	Cost / Rate on Invested Capital	Weighted Cost/Rate on Invested Capital
1	Long-Term Debt	$115,614,855	41.29%	47,737,374	8.06%	$3,847,632
2	Short-Term Debt	$115,614,855	10.54%	12,185,806	6.35%	$773,799
3	Common Equity	$115,614,855	48.17%	55,691,676	12.20%	$6,794,384
4	Rate of Return		100.00%	$115,614,855	**9.87%**	$11,415,815

Company Request:

	Description	Rate Base	Capital Structure	Rate Base by Source of Capital	Cost / Rate on Invested Capital	Weighted Cost/Rate on Invested Capital
1	Long-Term Debt	$119,568,615	41.29%	49,369,881	8.06%	$3,979,212
2	Short-Term Debt	$119,568,615	10.54%	12,602,532	6.35%	$800,261
3	Common Equity	$119,568,615	48.17%	57,596,202	12.50%	$7,199,525
4	Rate of Return		100.00%	$119,568,615	**10.02%**	$11,978,998

Cities Recommendation:

	Description	Rate Base	Capital Structure	Rate Base by Source of Capital	Cost / Rate on Invested Capital	Weighted Cost/Rate on Invested Capital
1	Long-Term Debt	$97,680,941	41.29%	40,332,461	8.06%	$3,250,796
2	Short-Term Debt	$97,680,941	10.54%	10,295,571	6.35%	$653,769
3	Common Equity	$97,680,941	48.17%	47,052,909	11.20%	$5,269,926
4	Rate of Return		100.00%	$97,680,941	**9.39%**	$9,174,491

Examiners' Summary of Parties' Cost of Equity Results

Energas - Cost of Equity

	Direct Testimony				Updated			
	Atmos		LDC's		Atmos		LDC's	
Constant DCF	High	Low	High	Low	High	Low	High	Low
DAM 6	10.49	8.54	8.39	6.75	12.33	9.91	8.71	7.37
DAM 7	16.78	14.83	11.69	10.06	15.65	13.24	12.00	10.66
DAM 8	16.79	10.33	12.19	9.22	18.47	12.56	13.49	10.65
DAM 9	11.62	11.43	8.07	7.9	9.96	9.77	7.68	7.55
DAM 10	17.91	17.72	11.38	11.2	13.29	13.10	10.97	10.85
DAM 11	17.91	13.22	11.88	10.37	16.11	12.42	12.46	10.84
Avg Constant DCF (1)	15.25 (a)	12.68 (b)	10.60 (d)	9.25 (e)	14.30 (a)	11.83 (b)	10.89 (d)	9.65
Avg of High and Low (2)		13.96 (f)		9.93 (g)		13.07 (h)		10.27
Atmos Avg less LDC's Avg (3)			4.04				2.80	
Atmos Direct Less Atmos Updated (4)						0.90		

	Direct Testimony		Updated	
CAPM	Atmos	LDC's Avg	Atmos	LDC's Avg
DAM 13	12.84	13.30	12.90	13.54
DAM 14	12.31	12.51	11.11	11.55

Notes: (1) The average of the results from the six DCF analyses.
(2) The average of (a) and (b) for Atmos results and the average of (d) and (e) for comparable LDCs results.
(3) (f) minus (g) for direct testimony results and (h) minus (i) for updated results.
(4) (f) minus (h) for Atmos results.

Aligned Cities - Cost of Equity

	Direct Testimony			Updated		
Constant DCF	Atmos	LDC's	Average	Atmos	LDC's	Average
(DJL-4)						
DCF HG1	12.16	9.76	10.10	10.26	9.09	9.26
DCF FG1	14.70	11.00	11.53	12.59	11.22	11.41
DCF HG2	11.15	10.14	10.29	10.81	9.33	9.54
DCF FG2	13.67	11.38	11.71	13.14	11.45	11.69
Avg DCF	12.92 (a)	10.57 (b)	10.91	11.70 (a)	10.27 (b)	10.48
Atmos Avg less LDC's Avg (1)		2.35 (d)			1.43 (e)	
Atmos Direct Less Atmos Updated (2)				1.22		

	Direct Testimony			Updated		
Non-Constant DCF	Atmos	LDC's	Average	Atmos	LDC's	Average
(DJL-6)						
5 Yr.	9.34	12.16	10.75	12.93	10.71	11.82
4 Yr.	10.06	13.96	12.01	14.85	12.76	13.80
Avg NC DCF	9.70	13.06	11.38	13.89	11.74	12.81

Notes: (1) (a) minus (b) for direct and updated testimony.
(2) (d) minus (e).

Energas Company
West Texas Distribution System

Examiners' Recommended Federal Income Tax

	Description	Energas' Request	Cities' Recommendation	Examiners' Recommendation
1	After Tax Return	$11,978,998	$9,174,491	$11,415,815
2	Interest Deduction	4,779,473	3,904,565	4,621,431
3	Equity Portion of Return	7,199,525	5,269,926	6,794,384
4	35% Tax on Equity Return	2,519,834	1,844,474	2,378,035
5	Tax Expansion Factor	1.53846	1.53846	1.53846
6	**Total Federal Income Tax Liability**	**$3,876,664**	**$2,837,650**	**$3,658,511**

Energas Company
West Texas Distribution System

Examiners' Recommended Revenue at Present Rates and Recommended Distribution Revenue

	Description	Energas' Request	Cities' Recommendation	Examiners' Recommendation	
1	**Revenues - Proposed**	$45,743,592	$45,743,592	$45,743,592	
2	Customer Adjustment		$90,580		
3	Weather Adjustment		64,266		
4	Rental Revenue	77,615	77,615	77,615	
5	LPL Pipeline Revenue	(120,000)	(120,000)	(120,000)	
6	**Revenues - Recommended**	**$45,701,207**	**$45,856,053**	**$45,701,207**	
	Adjustments to Determine Distribution Revenue:				**Sch.**
7	Revenues - Recommended	$45,701,207	$45,856,053	$45,701,207	
8	Current Other Revenue	($3,421,879)	($3,421,879)	($3,421,879)	(1)
9	Rental Revenue	(77,615)	(77,615)	(77,615)	
10	LPL Pipeline Revenue	120,000	120,000	120,000	
11	Current Distribution Revenue - Adjusted	42,321,713	42,476,559	42,321,713	
12	Net Revenue Deficiency (Surplus)	9,765,466	(6,250,374)	4,155,570	A
13	Service Charge (Increase) Decrease	(325,985)	-	(325,985)	(2)
14	Distribution Rates Total - Recommended	$51,761,194	36,226,185	46,151,298	

(1) Energas Ex. 5, JCC-B, Sch. 2.
(2) Energas Ex. 16, Ex. DMI-1, Sch. 1. Allocation factor of 71.0377% applied to $376,290.

Examiners' Schedule H

Rate Comparison - Current vs. Examiners' Recommended Rate Design

	General Service:	Current Rates				Examiners' Recommended Rates			
	Description	Charge / Rate	Bills / Volumes	Revenue	% of Total Revenue	Charge / Rate	Bills / Volumes	Revenue	% of Total Revenue
1	Customer Charge	$6.5000	2,657,546	$17,274,049	42.22%	$7.0882	2,657,546	$18,837,138	42.22%
2	1st Block (1-4 Mcf)	1.0800	7,720,696	8,338,352	20.38%	$1.1777	7,720,696	9,092,869	20.38%
3	2nd Block (5-10 Mcf)	1.0400	5,958,834	6,197,187	15.15%	$1.1341	5,958,834	6,757,956	15.15%
4	3rd Block (11-50 Mcf)	1.0100	4,900,111	4,949,112	12.10%	$1.1014	4,900,111	5,396,945	12.10%
5	4th Block (> 50 Mcf)	0.9900	4,196,893	4,154,924	10.16%	$1.0796	4,196,893	4,530,893	10.16%
6		**Demand**		17,274,049	42.22%	**Demand**		18,837,138	42.22%
7		**Commodity**	22,776,534	23,639,575	57.78%	**Commodity**	22,776,534	25,778,663	57.78%
8		**Total**		**$40,913,624**	100.00%	**Total**		**$44,615,800**	100.00%
	State Institutions:								
1	Customer Charge	$6.1800	1,556	$9,616	14.36%	$6.7392	1,556	$10,486	14.36%
2	1st Block (1-4 Mcf)	0.8900	4,783	4,257	6.36%	$0.9705	4,783	4,642	6.36%
3	2nd Block (5-10 Mcf)	0.8500	5,232	4,447	6.64%	$0.9269	5,232	4,850	6.64%
4	3rd Block (11-50 Mcf)	0.8200	18,319	15,022	22.43%	$0.8942	18,319	16,381	22.43%
5	4th Block (> 50 Mcf)	0.8000	42,032	33,626	50.21%	$0.8724	42,032	36,668	50.21%
6		**Demand**		9,616	14.36%	**Demand**		10,486	14.36%
7		**Commodity**	70,366	57,351	85.64%	**Commodity**	70,366	62,541	85.64%
8		**Total**		**$66,967**	100.00%	**Total**		**$73,027**	100.00%
	Small Industrial:								
1	Customer Charge	$28.5000	5,311	$151,364	11.53%	$31.0789	5,311	$165,060	11.53%
2	1st Block (1-50 Mcf)	0.7300	185,754	135,600	10.33%	$0.7961	185,754	147,871	10.33%
3	2nd Block (51-100 Mcf)	0.6700	138,431	92,749	7.07%	$0.7306	138,431	101,141	7.07%
4	3rd Block (> 100 Mcf)	0.6400	1,457,879	933,043	71.08%	$0.6979	1,457,879	1,017,471	71.08%
5		**Demand**		151,364	11.53%	**Demand**		165,060	11.53%
6		**Commodity**	1,782,064	1,161,392	88.47%	**Commodity**	1,782,064	1,266,483	88.47%
7		**Total**		**$1,312,755**	100.00%	**Total**		**$1,431,543**	100.00%
	Large A/C:								
1	Customer Charge	$0.0000	36	$0	0.00%	$0.0000	36	$0	0.00%
2	1st Block (> 0 Mcf)	0.6400	42,479	27,187	100.00%	$0.6979	42,479	29,647	100.00%
3		**Demand**		-	0.00%	**Demand**		-	0.00%
4		**Commodity**	42,479	27,187	100.00%	**Commodity**	42,479	29,647	100.00%
5		**Total**		**$27,187**	100.00%	**Total**		**$29,647**	100.00%
	Small A/C:								
1	Customer Charge	$6.5000	58	$377	32.03%	$7.0882	58	$411	32.03%
2	1st Block (1-2 Mcf)	1.0800	115	124	10.55%	$1.1777	115	135	10.55%
3	2nd Block (> 2 Mcf)	0.6400	1,056	676	57.42%	$0.6979	1,056	737	57.42%
4		**Demand**		377	32.03%	**Demand**		411	32.03%
5		**Commodity**	1,171	800	67.97%	**Commodity**	1,171	872	67.97%
6		**Total**		**$1,177**	100.00%	**Total**		**$1,284**	100.00%
	Totals:								
1		**Demand**	2,664,507	17,435,406	41.20%	**Demand**	2,664,507	19,013,095	41.20%
2		**Commodity**	24,672,614	24,886,305	58.80%	**Commodity**	24,672,614	27,138,206	58.80%
3		**Total**		**42,321,710**	100.00%	**Total**		**46,151,301**	100.00%
								(Sch. A)	

ENERGAS COMPANY
West Texas Service Area

GENERAL SERVICE RATE - RESIDENTIAL

AVAILABILITY

This schedule is applicable to general use by Residential customers for heating, cooking, refrigeration, water heating and other similar type uses. This schedule is not available for service to premises with an alternative supply of natural gas.

TERRITORY

West Texas Service Area

MONTHLY RATE

(a) Customer Charge ***$ 7.40***

(b) Commodity Charge:

First 50 Ccf per Month @	***$0.1110 / Ccf***
Next 100 Ccf per Month @	***$0.1040 / Ccf***
Next 100 Ccf per Month @	***$0.08641 / Ccf***
All Over 250 Ccf per Month @	***$0.0790 / Ccf***

(c) The West Texas Gas Cost Rider applies to this schedule.

EFFECTIVE: ***For Service Rendered on and After October 25, 2000***

ISSUED BY: ***C. W. Guy, Vice President - Rates and Regulatory Affairs***

ENERGAS COMPANY
West Texas Service Area

GENERAL SERVICE - STATE INSTITUTIONS RATE

AVAILABILITY

This schedule is applicable to gas service to state agencies (as provided in Texas Utilities Code, Section 104.202) including, but not limited to, state college and universities, MHMR schools, agriculture, highway and public safety departments, prisons, and other facilities owned or operated by the State of Texas for the purpose of heating, cooking, refrigeration, water heating and other similar type uses.

TERRITORY

West Texas Service Area

MONTHLY RATE

(a) Customer Charge *$ 30.88*

(b) Commodity Charge:

First 500 Ccf per Month @	*$0.0980 / Ccf*
Next 1500 Ccf per Month @	*$0.0790 / Ccf*
Next 2000 Ccf per Month @	*$0.0680 / Ccf*
All Over 4000 Ccf per Month @	*$0.0580 / Ccf*

(c) The West Texas Gas Cost Rider applies to this schedule.

EFFECTIVE: *For Service Rendered on and after October 25, 2000*

ISSUED BY: *C. W. Guy, Vice President - Rates and Regulatory Affairs*

ENERGAS COMPANY
West Texas Service Area

GENERAL SERVICE RATE - *COMMERCIAL*

AVAILABILITY

This schedule is applicable to general use by Commercial type customers including schools, hospitals and churches for heating, cooking, refrigeration, water heating and other similar type uses. This schedule is not available for service to premises with an alternative supply of natural gas.

TERRITORY

West Texas Service Area

MONTHLY RATE

(a) Customer Charge ***$ 9.65***

(b) Commodity Charge:

First 100 Ccf per Month @	***$0.1180 / Ccf***
Next 300 Ccf per Month @	***$0.1080 / Ccf***
Next 400 Ccf per Month @	***$0.0915 / Ccf***
All Over 800 Ccf per Month @	***$0.0810 / Ccf***

(c) The West Texas Gas Cost Rider applies to this schedule.

EFFECTIVE: ***For Service Rendered on and after October 25, 2000***

ISSUED BY: ***C. W. Guy, Vice President - Rates and Regulatory Affairs***

ENERGAS COMPANY
West Texas Service Area

GENERAL SERVICE RATE - *PUBLIC AUTHORITY*

AVAILABILITY

This schedule is applicable to general use by Public Authority type customers, including public schools, for heating, cooking, refrigeration, water heating and other similar type uses. This schedule is not available for service to premises with an alternative supply of natural gas.

TERRITORY

West Texas Service Area

MONTHLY RATE

(a) Customer Charge ***$ 32.50***

(b) Commodity Charge:

First 500 Ccf per Month @	***$0.1180 / Ccf***
Next 2000 Ccf per Month @	***$0.0980 / Ccf***
Next 2500 Ccf per Month @	***$0.0865 / Ccf***
All Over 5000 Ccf per Month @	***$0.0760 / Ccf***

(c) The West Texas Gas Cost Rider applies to this schedule.

EFFECTIVE: ***For Service Rendered on and after October 25, 2000***

ISSUED BY: ***C. W. Guy, Vice President - Rates and Regulatory Affairs***

ENERGAS COMPANY
West Texas Service Area

SMALL INDUSTRIAL RATE

AVAILABILITY

This schedule is applicable to the sales to any industrial or commercial customer whose predominant use of natural gas is other than space heating, cooking, water heating or other similar type uses. Service under this schedule is available to eligible customers following execution of a contract specifying the maximum hourly load. This schedule is not available for service to premises with an alternative supply of natural gas.

TERRITORY

West Texas Service Area

MONTHLY RATE

(a) Customer Charge ***$ 38.50***

(b) Commodity Charge:

First 1000 Ccf per Month @	*$0.0880 / Ccf*
Next 2000 Ccf per Month @	*$0.0730 / Ccf*
Next 3000 Ccf per Month @	*$0.0680 / Ccf*
All Over 6000 Ccf per Month @	*$0.0655 / Ccf*

(c) The West Texas Gas Cost Rider applies to this schedule.

EFFECTIVE: *For Service Rendered on and after October 25, 2000*

ISSUED BY: *C. W. Guy, Vice President - Rates and Regulatory Affairs*

ENERGAS COMPANY
West Texas Service Area

LARGE GAS AIR CONDITIONING AND/OR
ELECTRIC GENERATING GAS SERVICE

AVAILABILITY

This schedule is applicable to customers who require gas service for 50 tons or more of gas air conditioning equipment, or for 100 KW or more of gas driven electric generating equipment, or any combination thereof that has at least the equivalent of 50 tons of gas air conditioning equipment or 100 KW of gas driven electric generating equipment. This rate schedule does not apply to municipally owned power plants or electric utilities. This schedule is not available for service to premises with an alternative supply of natural gas.

TERRITORY

West Texas Service Area

MONTHLY RATE

The monthly bills shall be computed at the following rate:

(a) Gas used per month	***$0.06550 / Ccf***
(b) Minimum monthly bill	***$ 150.00***

(c) The West Texas Gas Cost Rider applies to this schedule.

EFFECTIVE: ***For Service Rendered on and after October 25, 2000***

ISSUED BY: ***C. W. Guy, Vice President - Rates and Regulatory Affairs***

ENERGAS COMPANY
West Texas Service Area

AIR CONDITIONING RATE RIDER

AVAILABILITY

This rider is available to any customer using new natural gas air conditioning equipment installed on the customer's premises on or after July 1, 1995 and will be in effect only during the months of May through September. During the months of October through April the customer's applicable rate schedule shall apply.

When gas service for non-residential air conditioning equipment is not separately metered, Energas will compute the volume used for non-residential air conditioning equipment on an individual customer basis using the following definitions:

Air Conditioning Load - Any consumption during the months of May through September that exceeds Base Load.

Base Load - The average monthly gas consumption during the months of May through September less any gas consumption for space heating or air conditioning purposes.

Base Load, as defined above, for existing non-residential customers will be determined by Energas on a historical consumption basis. Base Load for new non-residential customers will be determined by Energas on a connected load analysis basis and redetermined as necessary when actual Base Load consumption data becomes available. Rates for Base Load for this Rider will be billed from the General Service or Small Industrial rate schedules, whichever is applicable.

TERRITORY

West Texas service Area

MONTHLY RATE

(a) Customer Charge:

Residential Rate	***$ 7.40***
Commercial Rate	***$ 9.65***
Small Industrial Rate	***$ 38.50***

(b) Commodity Charge:

Residential

First 50 Ccf per Month @	***$0.1110 / Ccf***
All Over 50 Ccf per Month @	***$0.0655 / Ccf***

EFFECTIVE: ***For Service Rendered on and after October 25, 2000***

ISSUED BY: ***C. W. Guy, Vice President - Rates and Regulatory Affairs***

ENERGAS COMPANY
West Texas System

GAS COST ADJUSTMENT

GCA

APPLICATION

Gas bills issued under rate schedules to which this Rider applies will include adjustments to reflect decreases or increases in purchased gas costs or taxes. Any such adjustments shall be filed with the appropriate regulatory authority before the beginning of the month in which the adjustment will be applied to bills. The amount of each adjustment shall be computed as follows:

GAS COST ADJUSTMENT (GCA)

The GCA to be applied to each Ccf billed shall be computed as follows and rounded to the nearest $0.01:

$$GCA = (G/S + CF) \times TF$$

Where:

1. **"G", in dollars, is the expected cost of gas for the expected sales billing units.**
2. **"S", in Ccf at 13.6 psia, is the expected sales billing units to be billed to the customers in the respective sector of the Company's West Texas Service Area as shown on Page No. 3.**
3. **"CF", in $/Ccf at 13.6 psia, is a correction factor charge per Ccf to adjust for the cumulative monthly differences between the cost of gas purchased by the Company and the amount of gas cost billed the customer.**

   Once a year, on a 12 months ended September basis, the Company shall review the percentage of lost and unaccounted for gas. If this percentage exceeds 5% of the amount metered in, the correcting account balance will be reduced so that the customer will effectively be charged a maximum of 5% for lost and unaccounted for gas and the Company will absorb the excess.
4. **"TF" is a tax factor of 1.0526.**

The Company's base rates include a base cost of gas of $00.00/Ccf.

EFFECTIVE: ***For Service Rendered on and after October 25, 2000***

ISSUED BY: ***C. W. Guy, Vice President - Rates and Regulatory Affairs***

ENERGAS COMPANY
Odessa System

GAS COST ADJUSTMENT

GCA

APPLICATION

Gas bills issued under rate schedules to which this Rider applies will include adjustments to reflect decreases or increases in purchased gas costs or taxes. Any such adjustments shall be filed with the appropriate regulatory authority before the beginning of the month in which the adjustment will be applied to bills. The amount of each adjustment shall be computed as follows:

GAS COST ADJUSTMENT (GCA)

The GCA to be applied to each *Ccf* billed shall be computed as follows and rounded to the nearest $0.01:

$$GCA = (G/S + CF) \times TF$$

Where:

1. **"G", in dollars, is the expected cost of gas for the expected sales billing units.**

2. **"S", in *Ccf* at 13.6 psia, is the expected sales billing units to be billed to the customers in the Company's Odessa Service Area as shown on Page No. 3.**

3. **"CF", in $/*Ccf* at 13.6 psia, is a correction factor charge per *Ccf* to adjust for the cumulative monthly differences between the cost of gas purchased by the Company and the amount of gas cost billed the customer.**

   Once a year, on a 12 months ended September basis, the Company shall review the percentage of lost and unaccounted for gas. If this percentage exceeds 5% of the amount metered in, the correcting account balance will be reduced so that the customer will effectively be charged a maximum of 5% for lost and unaccounted for gas and the Company will absorb the excess.

4 **"TF" is a tax factor of 1.0526.**

The Company's base rates include a base cost of gas of $00.00/Ccf.

EFFECTIVE: ***For Service Rendered on and after October 1, 2000***

ISSUED BY: ***C. W. Guy, Vice President - Rates and Regulatory Affairs***

ENERGAS COMPANY
Midland System

GAS COST ADJUSTMENT

GCA

APPLICATION

Gas bills issued under rate schedules to which this Rider applies will include adjustments to reflect decreases or increases in purchased gas costs or taxes. Any such adjustments shall be filed with the appropriate regulatory authority before the beginning of the month in which the adjustment will be applied to bills. The amount of each adjustment shall be computed as follows:

GAS COST ADJUSTMENT (GCA)

The GCA to be applied to each Ccf billed shall be computed as follows and rounded to the nearest $0.01:

$$GCA = (G/S + CF) \times TF$$

Where:

1. **"G", in dollars, is the expected cost of gas for the expected sales billing units.**

2. **"S", in *Ccf* at 13.6 psia, is the expected sales billing units to be billed to the customers in the Company's Midland Service Area as shown on Page No. 3.**

3. **"CF", in $/*Ccf* at 13.6 psia, is a correction factor charge per *Ccf* to adjust for the cummulative monthly differences between the cost of gas purchased by the Company and the amount of gas cost billed the customer.**

   Once a year, on a 12 months ended September basis, the Company shall review the percentage of lost and unaccounted for gas. If this percentage exceeds 5% of the amount metered in, the correcting account balance will be reduced so that the customer will effectively be charged a maximum of 5% for lost and unaccounted for gas and the Company will absorb the excess.

4. **"TF" is a tax factor of 1.0526.**

The Company's base rates include a base cost of gas of $00.00/Ccf.

EFFECTIVE: ***For Service Rendered on and after october 1, 2000***

ISSUED BY: ***C.W. Guy, Vice President - Rates and Regulatory Affairs***